THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAI'I

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Competitive Bidding for New Generating Capacity in Hawaii.	)	Docket No. 03-0372

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PUBLIC UTILITIES COMMISSION

FINAL STATEMENT OF POSITION

WITNESS LIST

EXHIBITS I – III

AND

CERTIFICATE OF SERVICE

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAI'I

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FINAL STATEMENT OF POSITION

Hawaiian Electric Company, Inc. ("HECO"), Maui Electric Company, Limited ("MECO"), and Hawaii Electric Light Company, Inc. ("HELCO") (HECO, HELCO and MECO are collectively referred to as the "HECO Companies") respectfully submit their Final Statement of Position ("FSOP"), pursuant to Prehearing Order No. 20923, issued April 23, 2004, as modified by Order No. 21575, filed January 28, 2005, in Docket No. 03-0372.

I. COMPETITIVE BIDDING

1. The HECO Companies can support competitive bidding for certain forms of new generation, but only if it is structured in such a fashion that the potential benefits can be realized, and the potential disadvantages can be mitigated or eliminated, and only if appropriate exceptions are recognized.

2. As was indicated in their Statement of Position filed March 14, 2005 ("SOP"), the HECO Companies have reservations about the applicability of competitive bidding to their small, isolated island systems. There are a number of concerns regarding the potential

shortcomings of a competitive bidding process that should be addressed in the design, development and implementation of any competitive bidding program.

3. Hawaii specific factors that must be taken into consideration in determining whether to proceed with competitive bidding for new generation, and/or in designing a competitive bidding program include (a) the very limited number of sites that are available to site new generation, and the difficult, time-consuming and uncertain process that must be followed to change land use designations in Hawaii in order to acquire new sites for generation, (b) the extended time that must be allotted to conduct the necessary environmental review for, and to permit and obtain the necessary approvals for, new generation, (c) the utility and island-specific constraints that constrain the size of new generation that can be added to the systems, and (d) the limited fuel options that are economically available in Hawaii.

4. The objectives of competitive bidding should be established to assess whether competitive bidding in general, or a specific competitive bidding process, will be beneficial.

a. In order to meet the needs of a small, isolated island utility, the generation acquired under a competitive bidding process must meet the needs of the utility in terms of the reliability of the generating unit, the characteristics of generation needed by the utility, and the control that the utility needs to exercise over the operation of the generating unit in order to integrate the unit into its system.

b. Under state energy policy, the utility's focus is first on acquiring new renewable energy generation. That means that the competitive bidding process, if any, must facilitate the acquisition of renewable energy generation, and that other types of generation added to the system should accommodate the introduction of more renewable energy generation to the utility's system. See response to HREA-HECO-IR-6.

c. Hawaii utilities must have adequate assurances that new, firm capacity generation will be added when it is needed. Hawaii utilities do not have the option to acquire power from other jurisdictions, or even other islands, to backup the unfulfilled commitments of IPP developers of generation.

5. The implementation of competitive bidding cannot be allowed to negatively impact the reliability of the electric utility system. The Hawaiian Islands have no interconnections with other islands, and certainly are not interconnected with large mainland electric utility systems.

a. The HECO Companies already are committed to purchase a high percentage of firm capacity and energy from independent power producers ("IPPs").

b. Differences in the reliability impacts and risks of IPP-owned generation and utility-owned generation must be taken into consideration in evaluating bids, and measures to mitigate the risks must be incorporated into PPAs, to the extent practical.

c. In addition, the presence of a Power Purchase Agreement ("PPA") between the utility and an IPP does not provide the utility with as much operating flexibility as the utility has with its own units. While the PPA can specify operating conditions favorable to the utility (such as coordination of maintenance, dispatchability, etc.), the utility generally has less control over plant maintenance practices, operational considerations, fuel conversion opportunities, and environmental enhancements. In contrast, the utility has such operating flexibility with its own units.

d. Utilities have the obligation to serve their customers while IPPs who supply capacity and energy to the utilities under PPAs may be obligated to provide to the utility only those items and services, or to perform only those duties, that are covered by provisions in the PPA. At times, this can constrain the utility's operating flexibility. As a result, a utility has much more flexibility to adjust to changed circumstances if it owns and operates it own units, than if it purchases power under long-term PPAs, because PPAs cannot be drafted to provide for all future contingencies and changed circumstances.

e. By the same token, the PUC can not exercise the same level of regulatory control over IPPs that it has over the utility. In particular, the PUC does not generally have access to the financial information of IPPs or control over their profitability to ensure that the utility system customers receive an adequate benefit for the power being purchased. As the level of power purchased from IPPs increases, the PUC must increase reliance on the utility's ability to manage the IPP performance through the terms and conditions of its contracts.

f. Existing firm capacity contracts generally have allowed an IPP to not proceed with its project if it is unable to obtain financing on acceptable terms. For firm capacity IPP projects, the risk that the IPP will not proceed or will not complete its project if financial conditions change, will likely result in maintaining the requirement for parallel planning and close coordination between a utility and developer to ensure an IPP project meets its milestones will be required. The first notice of failure to meet the milestone schedule may result in a triggering of a parallel planning process and a back-up supply plan should the project fail. If the IPP defaults on its PPA after commencing service, the utility may have to take over a facility (and the underlying contracts and financing) that it would not have built to begin with. Also, reliability concerns should lead to more stringent security provisions and higher bidder qualification standards to ensure the bidder has the incentive to meet its obligations under the contract.

6. In order to ensure that the generation they acquire is at the lowest reasonable cost, utilities must be able to take into account all utility cost impacts that the addition of the new generation will have on the utility. If the addition of the new generation will require the addition

of new transmission resources, then that will impact the cost of adding the new generation to the utility's system, and may impact the amount of time required to add the new generation to the utility's system. If the utilities will have to restructure their balance sheets and increase their percentage of more costly equity financing in order to offset the impacts of purchasing power on their balance sheets, then this rebalancing cost must also be taken into account in evaluating the total cost of the new generating unit.

7. Exceptions to any mandated competitive bidding process must be allowed when the competitive bidding process would not allow needed generation to be added in a timely fashion, and when another competitive procurement process would be more efficient. Proposed exceptions are described in Exhibit II.

a. Because of the length of time needed to develop and implement a well-designed competitive bidding process, and to permit and install new generation, certain utility capacity addition projects already under development should not be subject to the competitive bidding process. For example, HECO currently has an urgent need for firm generating capacity. Efforts to install a simple cycle peaking unit at Campbell Industrial Park have been under way since early 2003. Although the capacity to be provided by the unit is needed now, the unit is not expected to be installed sooner than 2009, because of the long lead time for environmental review, permitting and approvals, equipment procurement and construction. It would not be practical for this unit to be subject to competitive bidding, because a well-designed and effective competitive bidding process cannot be put into place and completed soon enough.[1]

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[1] SOP, Exhibit A, pages 8-9; Responses to PUC-IR-15.a, CA-HECO-13.b.

If an IPP-owned peaking unit was selected through a new competitive bidding process adopted as a result of this proceeding, the unit would not be installed until several years beyond 2009. This assumes that it could take 4 to 8 months to complete this proceeding, 12 to 24 months to approve a new competitive bidding process, 4 to 8 months to initially implement the process, and seven years or more to obtain environmental review of, and permits and approvals for, and to acquire the equipment for and install, the new generation. It would be imprudent to apply the new process to generation that has to be

b. In addition, it simply is not possible to precisely forecast what the future will look like ten years from now. Loads may grow faster than expected, the utilities may be unsuccessful in achieving the implementation rates that they have forecast for demand-side options, or other factors may accelerate the need for new generation. Just as IRP has to allow for the implementation of contingency options when planning assumptions and forecasts change, any competitive bidding process would have to allow for similar exceptions.

c. The expected timeline to (i) complete an IRP cycle, bid, (ii) select, contract for and obtain approval for a new generating unit (whether an IPP or utility-owned unit), and (iii) then permit and install the new unit must be realistic, and cannot be based on wishful thinking to justify a competitive bidding process. The reality is that it takes substantially longer in Hawaii to complete many of these steps than on the Mainland, and that the time required for some of these steps has lengthened in recent years.

d. The competitive procurement process for distributed generation ("DG") should be different than the competitive procurement process for generation that provides power directly to the utility or sells power to the utility. The competitive procurement procedure that the HECO Companies propose to use for combined heat and power ("CHP") systems that are installed at customer sites was detailed in the generic DG investigation, Docket No. 03-0371.

e. As-available renewable energy generation has different characteristics than firm capacity, and the timing of when such resources are added to the utility's system is not nearly as important to the reliability of the system. It may be appropriate to establish a separate

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added earlier than the process could be completed, even if some form of "expedited" process was followed.

Based on the experiences in other states, it may take two years or more to develop the bidding rules. Once the rules are established, it may take two years or more to prepare an RFP, solicit proposals, evaluate the proposal, select the winning bidder and negotiate a contract. It could then take another seven years for the utility to obtain approval of the contract, and the selected bidder to obtain the necessary permits, procure the necessary equipment, and construct the unit.

competitive procurement process to acquire as-available renewable energy generation, particularly given state energy policy that favors the development of renewable energy generation.

II. COMPETITIVE BIDDING PROCESS

8. The HECO Companies propose that the competitive bidding process, if implemented as a result of this proceeding, be a multistage process involving (1) development of the RFP, (2) issuance of the RFP and development of bids by bidders, (3) evaluation of the bids, (4) contract negotiations, if a third-party bid is selected, and (5) regulatory approval. These stages are described in detail in Exhibit I.

9. The roles of the host utility in the competitive bidding process should include: (1) designing the RFP documents, evaluation criteria, and power purchase agreement; (2) managing the RFP process, including communications with bidders; (3) evaluating the bids received; (4) selecting the bids based on the established criteria; (5) negotiating contracts with selected bidders; and (6) competing in the solicitation process with a self-build option, if feasible.

a. All of these roles for the host utility are common in most RFP processes and are recognized by regulators and third-party bidders as reasonable roles for the host utility. Recent competitive bidding dockets have recognized the role of the utility and have supported an active role for the host utility. In fact, in several recent RFP processes, utility self-build or turnkey options have been the successful bidders among a large number of options.

b. Regulatory commissions have recognized that utilities have an obligation to serve and provide reliable service, and have an obligation to do so at lowest reasonable cost. Regulatory commissions also have recognized that acquisition of energy and capacity to meet the needs of customers remains the responsibility of the utility, and that these functions should not be delegated to an independent entity.

c. The goal of any competitive bidding process is to encourage and evaluate a range of generation options with the objective of obtaining the best option for the customers of the utility. This goal can only be assured if all resource options are allowed to compete. Regulatory commissions have recognized that a utility project may be the lowest cost option and failure to allow that option to compete may result in higher cost power options, contrary to their goals and objectives.

d. With regard to host utility self-build options, utilities have been selecting their own build options more frequently over the past few years for several reasons. First, the financial and credit problems faced by independent generators have led to higher debt costs and higher equity ratios for independent generators, virtually eliminating the competitive advantage once enjoyed by independent generators. Utility projects are now competitive from a financial perspective. Second, transmission constraints in a number of markets have led to higher transmission costs for resources located outside the utility service area or in costly transmission areas. Third, the deteriorating credit quality of many independent generators has raised concern over counter-party reliability. In turn, power purchase agreements require higher levels of security and tighter damage provisions to protect the utility's customers against the prospect of contract default. There is heightened concern that independent generators are less reliable than host utilities in developing and operating their projects.

10. Competitive bidding will not be beneficial in Hawaii unless electric utilities are able to (1) participate as bidders in the process, and (2) conduct the competitive bidding process (which includes sending out the RFP, pre-qualifying bidders, evaluating the bids, and selecting

the winning bid or bids). In order to encourage bidder participation, and to minimize disputes arising out of the bid evaluation and selection process, the HECO Companies have described steps that can be considered to facilitate a "fair" process in Exhibits I and II. The steps that should actually be taken must take into account limitations on the resources of the utilities implementing the process, and the time required to take the step.[2] Given the dual role of the utility in the process, the steps the utility can take to avoid self-dealing or concern over an unfair competitive advantage that may be perceived by other bidders include:[3]

a. The utility could submit its self-build option to the PUC one day in advance of receipt of other bids. The utility could also provide substantially the same information as other bidders. By sending its proposal to the PUC in advance other bidders would be ensure that the utility could not adjust its bid price or project structure after reviewing other proposals.[4]

b. The utility could establish a website devoted to disseminating information to all bidders at the same time, including the utility self-build option. All bidders would therefore have access to the same information at the same time ensuring bidders are treated fairly and equitably.

c. The utility could use an independent observer to review the solicitation process (including communications with bidders), bid evaluation and selection, and contract negotiations, and report to the PUC at various steps of the process.

d. The Commission would then approve the result of the process by approving the commitment of expenditures for utility-owned generation and/or the power purchase agreement ("PPA") for generation owned by IPPs.

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[2] For example, obtaining PUC approval of an RFP before it is issued might minimize later issues regarding the RFP, but such a requirement could add substantially to the time required to conduct an RFP process (particularly if the approval was made in a 'contested case" proceeding. Thus, prior approval is not recommended.

[3] The recommended steps to address the perceived fairness of the RFP process, and to facilitate PUC review of the result of the process, also are discussed in Exhibit II. See response to PUC-IR-23.

[4] See response to PUC-IR-47.

11. The RFP, the form of PPA that is attached to the RFP, and the RFP evaluation/selection process, should address the reliability issues identified above and the utility's need for flexibility, as discussed in Exhibits I and II.

a. Given state energy policy, the Companies have been aggressively pursuing resources other than fossil-fuel generation, including energy efficiency demand-side management ("DSM") programs, load management DSM, combined heat and power systems, and renewable energy generation. As a result, the utilities need to be able to adjust their plans to add new fossil-fuel generation to take into account their success or lack of success in obtaining the necessary approvals to implement these other resources, and their success in obtaining customer acceptance of these resources (since they are often dependent on the plans of third-parties other than the utilities), and to adjust for changes in load growth.

b. The competitive bidding process should recognize the value of flexibility in the evaluation of resource alternatives. Such flexibility options as contract buy-out options, project in-service date deferral or acceleration provisions, or project acquisition options are valuable options for a utility to more effectively balance its needs with the cost of obtaining such options. Given the nature of their Island systems, the HECO Companies are also concerned about fuel flexibility and the option to convert to an alternative fuel if fuel cost or availability changes dramatically.

c. The inclusion of turnkey projects provides the correct signals for the bidder to structure its project recognizing the value of the project structure. For example, if bidders are concerned that a straight power purchase agreement will not be competitive if financial impacts are accounted for during the evaluation, the bidder will also have the option to offer a turnkey arrangement as well.

III. COMPETITIVE BIDDING GUIDELINES

12. The details of the competitive bidding process should be developed in a follow up proceeding, based on the principles enunciated by the Commission in this proceeding. The HECO Companies prefer that the procedures be developed and adopted in a framework proceeding, like that used to develop the IRP Framework, rather than in a rulemaking proceeding. The development and implementation of a competitive bidding process can be a very time consuming process, generally taking several years to complete. However, taking the time necessary to effectively develop the process in the early stages serves to avoid the potential for very costly mistakes and potential delays later in the process. See Exhibit II.

IV. INTEGRATION OF COMPETITIVE BIDDING WITH OTHER PROCESSES

13. The competitive bidding process should be integrated with the integrated resource planning ("IRP") process.

a. The IRP Plan can continue to be developed using the current process followed by the HECO Companies. In this case, the role of the IRP Plan should be to identify the preliminary "preferred" resource plan, define capacity and energy requirements, the timing of need, any preferred technologies, and potentially any other preferred attributes. The IRP Plan can also be used to identify any preferences or criteria for resource selection and can be used to determine avoided costs.

b. In this model, the role of the RFP would include the solicitation and evaluation of resource options to meet the capacity and energy needs identified in the preliminary preferred resource plan. The RFP can be used to solicit bids for either a block of resources as defined in the IRP Plan or for the next required resource identified in the IRP Plan. Bidders would be allowed to submit proposals for any variety of resource types and sizes. The utility also would have the right to submit proposals for resources that may differ from the preferred resource type included in the preliminary resource plan. The bids received in response to the RFP would be evaluated relative to one another and/or to the avoided costs of the generic resource identified in the IRP Plan or to the utility self-build project. The IRP Plan would establish the parameters for the RFP. After the bids are evaluated and the preferred resource selected, the utility would then build the resource (if a self-build system is selected), or negotiate a turnkey contract or power purchase agreement ("PPA") with the winning bidder (if a turnkey or PPA option is selected). The utility would essentially complete its preferred resource plan after the bids are received -- the final bid(s) selected would be part of the final IRP Plan.

14. The competitive bidding process generally should supercede the process of negotiating PPAs under the PUC's "Standards for Small Power Production and Cogeneration", which were adopted pursuant to the Public Utility Regulatory Policies Act of 1948 ("PURPA"), and the rules promulgated by the Federal Regulatory Energy Commission under PURPA, and H.R.S. § 269-27.2.

V. COMPETITIVE BIDDING DOCKET ISSUES

15. The key issues in this docket are (1) whether Hawaii electric utilities should implement competitive bidding for new generation, (2) what competitive bidding process, if any, should be implemented, (3) which resources should be subject to the competitive bidding process (since there are significant differences between central station firm capacity, distributed generation, and as-available renewable energy generation), (4) how should competitive bidding procedures be developed, and (5) how should such a competitive bidding process be "integrated" with the integrated resource planning ("IRP") process? The positions of the HECO Companies on these issues, and support for the positions, are included in Exhibit I to this FSOP.

a. The questions are not independent. (For example, competitive bidding using the wrong competitive bidding process should not be implemented.) Moreover, the answers to the questions may not be the same for each type of resource.

b. It would be a mistake to focus only on the "concept" of competitive bidding in this docket. Most of the parties can hypothecate that competitive bidding will be beneficial, but there are practical realities that could make certain forms of competitive bidding detrimental in practice.

c. Mainland models can serve as a guide in developing Hawaii guidelines.[5] However, a "conceptually-sound" process that works on the mainland, but ignores Hawaii's unique reality, could result in substantial harm to Hawaii's electric infrastructure, to the ability of Hawaii's electric utilities to meet the growing electricity needs of their customers, and to Hawaii's economy.

d. The devil is in the details. The pros and cons of competitive bidding definitely will depend on the type of competitive bidding process implemented. The HECO Companies have provided a substantial amount of information regarding competitive bidding processes in Exhibit I, and present their positions and comment on the positions of the CA and HREA with respect to the most important process issues in Exhibit II.

VI. CONCLUSION

16. The HECO Companies recognize that regulators may be predisposed towards competitive bidding, and a number of jurisdictions on the mainland have implemented some form of competitive bidding. The HECO Companies themselves routinely use competitive procurement practices in acquiring and constructing utility equipment and facilities, and are

[5] See response to PUC-IR-27.

experienced in issuing RFPs for major equipment purchases. HECO issued an RFP in 1987 that ultimately resulted in two major PPAs for firm capacity.

17. However, the decision whether to implement competitive bidding in Hawaii today, in order to increase the number of IPP-owned options considered by utilities when adding new generation, should not be based on the conceptual benefits of competitive bidding, or the actual benefits of issuing an RFP to acquire new capacity in the mainland markets, or the perceived benefits of issuing an RFP in 1987. As is shown in Exhibit III, circumstances are substantially different now than they were in 1987, and are substantially different than they are on the mainland in terms of sites, fuels and other features that may make alternatives attractive. Even on the mainland, utility-owned options are often the most attractive options available.

18. In summary, competitive bidding for new generation has not been shown to be necessary in Hawaii. Under existing contracts and approved contracts for new facilities, the HECO Companies purchase a high percentage of firm power and energy from IPPs. Increasing the percentage of purchased power, especially firm purchased power, may well be detrimental to utility reliability.

19. In addition, the HECO Companies have aggressively pursued the purchase of power from facilities generating electricity from renewable resources. Within the last two years, the PUC has approved three as-available energy contracts under which HELCO and MECO are committed to purchase a substantial amount of wind-generated energy. HECO's subsidiary, Renewable Hawaii, Inc. has issued two sets of RFPs in an effort to encourage developers to submit proposals for additional renewable energy facilities.

20. HECO also recognizes, however, that the CA recommends that competitive bidding for new generation be implemented, and has speculated in recent power purchase contract

approval proceedings that better prices, or better contract terms and conditions, might have been obtained had competitive solicitations been used to acquire additional renewable energy resources. While the CA's speculation ignores certain realities (such as a limitation on sites), such questions may continue to be raised unless a competitive procurement process is used.

21. Thus, despite their reservations, the HECO Companies can support competitive bidding for certain forms of new generation, if it is structured in such a fashion that the potential benefits can be realized, and the potential disadvantages can be mitigated or eliminated, and if appropriate exceptions are recognized.[6]

DATED: Honolulu, Hawaii, August 11, 2005.

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HAWAIIAN ELECTRIC COMPANY, INC.
HAWAII ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED.

[6] This docket was opened to address competitive bidding for new generation. Thus, competitive bidding for DSM resources is clearly beyond the scope of this docket. In fact, the acquisition of DSM resources is the subject of the energy efficiency docket opened by the PUC, Docket No. 05-0069.

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WITNESS LIST

Pursuant to Prehearing Order No. 20923, issued April 23, 2004, as modified by Order No. 21575, filed January 28, 2005, in Docket No. 03-0372, the Parties and Participants are to identify the witnesses who will be made available at the Panel Hearing.

The witnesses for the HECO Companies and their areas of responsibilities are as follows:

<u>**Witness**</u>	<u>**Area of Responsibility**</u>
1. **Wayne Oliver** Merrimack Energy Group, Inc.	Competitive Bidding, Competitive Bidding Processes, Competitive Bidding Guidelines, Integration of Competitive Bidding with other Processes, Competitive Bidding Issues
2. **Leon R. Roose** Manager Power Supply Services Power Supply Department	Competitive Bidding-HECO Companies Perspective, Competitive Bidding Processes-HECO Companies Perspective, Competitive Bidding Guidelines-HECO Companies Perspective, Integration of Competitive Bidding with Other Processes-HECO Companies Perspective, Competitive Bidding Issues-HECO Companies Perspective
3. **Ross H. Sakuda** Director Generation Planning Division Power Supply Planning and Engineering Dept	Competitive Bidding Exceptions

4. **Thomas C. Simmons** Reliability Issues
Vice President
Power Supply Department

5. **Robert A. Alm** Regulatory Policy
Senior Vice President
Public Affairs Department

EXHIBIT I

POSITIONS OF THE HECO COMPANIES ON THE ISSUES LISTED IN PREHEARING ORDER NO. 20923

Issue 1. What are the benefits and impacts of competitive bidding?

HECO/HELCO/MECO Position:

A. Potential Benefits of Competitive Bidding

The potential benefits of competitive bidding include the following:

1. Bidding has encouraged increased competition in some areas.

The response of bidders to competitive bidding processes has varied depending on the location, requirements of the soliciting utility, and cost to develop a project. For a number of processes, the ratio of bids received to MW solicited has averaged between 8-10 to 1. In active power markets, ratios in excess of 10 to 1 have not been uncommon.

The HECO Companies caution that the response to a competitive bidding process in Hawaii will likely not achieve the same level of activity as on the mainland. This is due to the smaller capacity requirements in Hawaii, the lack of merchant plants seeking power contracts, lack of short-term options, and more limited market access. In addition, development costs are likely to be higher and economies of scale are not significant.

2. Competitive bidding can promote an organized, structured process

An important benefit of competitive bidding is that all bidders and proposals participate in an organized, structured process. This is generally accomplished through a bidding process that requires all bids to be submitted at the same time, with all bidders providing complete and consistent information, with all bids being evaluated based on the same set of economic and fuel price assumptions, and with all bidders playing by the same set of rules. The evaluation of unsolicited proposals, such as traditional PURPA projects, can be complicated by different timing for proposal submission, and incomplete or inconsistent proposals. If the utility's PURPA obligations are not superseded by the competitive bidding process, one of the major benefits of competitive bidding may not be realized. As noted in more detail in HECO's response to PUC-IR-20, in some states competitive bidding processes replaced the process for contracting with PURPA QFs, resulting in a greater level of benefits to customers.

3. Bidding has often contributed to competitive prices and more choices

One of the primary goals of competitive bidding is to solicit and evaluate a wide range of resource options so that the best deals (among a range of options) for customers are selected.

On the mainland, the overall experience with competitive bidding programs is that competition has led to a range of prices and products with the opportunity to select lower cost options. This has been due to several factors. First, the level of competition has generally been significant and has included a range of different product options. In addition, the recent glut in merchant power generation and the financial problems faced by a number of power generators are leading some project developers to lower their expected returns to compete. Second, in many RFPs there have been one or two bidders who aggressively price their product to compete or are uniquely positioned to offer lower prices. Competitive bidding can help identify such options. Third, Independent Power Producer ("IPP") generation contracts are generally performance-based contracts that require the generator to guarantee a minimum level of performance or be subject to penalties. IPPs may be more willing to accept provisions allocating more cost and operational risks if they are bidding against other potential project developers. (However, they may seek "out" clauses if they are not able to pass the risks on to their contractors, or if their financing parties are unwilling to accept the risks.)

4. Bidding can encourage the development of new technologies and products

Effectively developed competitive bidding processes can encourage a wide range of options, including new technologies. Competitive bidding programs over the years have led to the selection of a wide range of resource options, rapid improvement of several generation technologies, enhanced market efficiencies, and creative project financial and contract structures.

While natural gas-fired combined cycle options have been the dominant form of capacity contracted through competitive bidding processes, other resources have been selected as well. Contracts for renewable resources have been increasing and many projects have been selected either through all supply source RFPs or targeted solicitations. Care must be taken, however, to develop a competitive bidding framework that enhances or is at least neutral toward resources that may be favored from a public policy perspective, such as renewables.

In addition, bidders have been very creative in structuring their proposals and attempting to distinguish their proposals from their competitors through any inherent competitive advantage gained through technology advantages, financing, fuel supply, operations and maintenance, or other unique capabilities or market niches.

5. Competitive bidding allows the host utility to clarify unique system characteristics in the RFP

Another advantage of competitive bidding is the ability of the host utility to include important and unique system requirements in the RFP. RFP documents generally contain a significant amount of information regarding the requirements of the utility, the resource attributes of importance to the utility, the criteria used for the evaluation, and other important criteria. For example, if the utility values dispatchability or other operating flexibility associated with a proposed unit, it could request that a bidder offer such an option and/or evaluate the impacts of dispatchability or operational flexibility in the bid evaluation process. Likewise, a well structured competitive bidding framework allows the utility to more effectively integrate a new unit into its system by valuing such factors as location, transmission access/cost of system upgrades, operational flexibility, financial impact, in-service date flexibility, and fuel supply access into the RFP and evaluation process. When unsolicited proposals are negotiated without competition, often the developer is aware of the utility's priorities, but is not sufficiently motivated to incorporate them into the project. In a well-structured competitive bidding process, however, bidders will have an incentive to structure their proposals to meet the utility's requirements,

6. A properly structured competitive bidding process can limit self-dealing

In most RFP processes, the host utility plays a major role in the competitive bidding process including: (1) designing the RFP documents, evaluation criteria, and power purchase agreement; (2) managing the RFP process, including communications with bidders; (3) evaluating the bids received; (4) selecting the bids based on the established criteria; (5) negotiating contracts with selected bidders; and (6) competing in the solicitation process with a self-build option, if feasible.

A 1996 study by the National Regulatory Research Institute (NRRI) entitled State Commission Regulation of Self-Dealing Power Transactions focused on issues associated with self-dealing and concluded that competitive bidding can limit self-dealing. The study also concluded that not allowing a utility bid or project to compete could eliminate the lowest cost and most viable option.

If the host utility is prohibited from bidding, this clearly removes a significant opportunity for self-dealing. However, this also precludes the possibility that the utility may in fact be the lowest-cost and most viable provider. Also, having the utility as the provider carries the advantages of lower transactions costs and potentially better reliability assurance. There are also cost savings associated with the economies of scope and better integration of generating facilities to the transmission grid. Also, the host utility is usually subject to ex post prudence reviews that provide some protection against the utility's preferential treatment of itself over other suppliers (Page 33).

The "solution" has been to use an "independent observer" to monitor and report on the utility's conduct of its bidding process, evaluation of the bids, and selection of the winning bidder. This solution, however, can add to the cost of the process.

7. Competitive bidding can provide greater regulatory certainty

Conceptually, the selection of resources through a market test should serve to facilitate the regulatory process and alleviate the possibility for extended proceedings and the uncertainty associated with cost recovery and regulatory approvals. A well-designed and implemented RFP process can minimize the risk of legal challenges to the results of the procurement process.

B. Potential Disadvantages of Competitive Bidding

While there are a number of advantages or benefits associated with competitive bidding there are also a number of potential disadvantages or major issues that must be recognized and addressed before a competitive bidding process can be effectively developed. These include:

1. **Implementation of competitive bidding can lead to increased reliability risk**

   The isolated nature of the island's electrical system places a premium on reliability of power supply and increases the risk of project default and/or the failure of the independent generator to deliver the power. Unlike the mainland, Hawaii's electric utilities cannot resort to purchases of energy from the market during periods of generation shortfall if the project does not deliver the power as required under the contract. In many cases, project sponsors develop a proposal designed to win the solicitation, but realize later that in attempting to compete, it has priced its power too low to remain economically viable. HECO's response to CA-HECO-IR-14 details cases, two of which occurred in Hawaii, in which a bidder was either selected as the preferred project or actually signed a contract and failed to complete the project. Similarly, HECO's response to CA-HECO-IR-15 documents cases where developers have been known to walk away from partially or nearly completed projects simply because the cost of completing the project and operating the facility were not economically viable. Delays in power plant development or the ultimate failure of a project to achieve commercial operations could have significant impacts on an island system. The non-Hawaii cases are examples where very large projects were abandoned; projects that could exceed Hawaii's competitively bid projects by 500 – 1500 MW. Given the overall track record, it is prudent to consider the probability that relatively small projects, with correspondingly small committed funds, could be abandoned in the future.

   In addition, increases in the penetration of non-utility resources could exacerbate reliability concerns if projects do not perform in accordance with their contracts during operations, or new technologies introduce unintended consequences. While a competitive bidding system encourages lower cost bids, and the shifting of risk to project sponsors, incentives to lower cost could lead to poor operating performance or project failure if the bidder has not effectively managed risk.

   The presence of a Power Purchase Agreement ("PPA") between the utility and an IPP does not provide the utility with as much operating flexibility as the utility has with its own units. While the PPA can specify operating conditions favorable to the utility (such as coordination of maintenance, dispatchability, etc.), the utility generally has less control over plant maintenance practices, operational considerations, fuel conversion opportunities, and environmental enhancements. In contrast, the utility has such operating flexibility with its own units.

Hawaii utilities have the obligation to serve their customers while Independent Power Producers ("IPPs") who supply capacity and energy to the utilities under PPAs may be obligated to provide to the utility only those items and services, or to perform only those duties, that are covered by provisions in the PPA. At times, this can constrain the utility's operating flexibility. The following examples illustrate how the utilities operating flexibility can be constrained by IPPs.

Over the years, utilities have developed contractual provisions for PPAs that attempt to address the operational constraints utilities face with IPPs. HECO's response to PUC-IR-8 addresses contractual mitigation in detail. But, as indicated in the HECO response, although these provisions can resolve some of the constraints, contracts cannot fully mitigate them.

- An IPP may be reluctant to increase its expenses in order to hasten a return from a planned maintenance outage to accommodate the utility's need for capacity at a particular time.

- An IPP that is capable of providing more capacity than it is obligated to under the terms of the PPA may limit the output of its facilities to the grid, even though the utility may have a need for the capacity at a particular time. The utility would need to rely on persuasion and cooperation arising from good business relationships in order to obtain anything beyond the terms of the PPA.

- IPPs are dispatched based on PPA pricing provisions, which often contain pricing curves. If it turns out that the pricing curves do not actually track the IPP's costs, then the IPPs will seek to be dispatched (and will exercise their rights under the PPA) so as to maximize their profitability (taking into account differences between their prices and costs), not to minimize the utility's costs.

- An IPP may refuse to operate during certain periods of the week because it is more economical to pay a penalty according to the PPA for being unavailable than to operate.

- An IPP may be experiencing frequent forced outages, which may result in service interruptions to utility customers. Yet the utility only has a limited amount of latitude under most PPAs to require evaluations of the IPPs power plant configuration, and to design and specify improvements to reduce the number of forced outages.

- Many IPP units are designed, built, owned and operated by mainland- or foreign-based corporations who may not fully understand the intricacies of operating small, isolated, non-interconnected island grids. Often they do not comprehend the relative impact of their generation on these smaller isolated grids, and may resist operating under system conditions such as low frequency, low voltage, high frequency or high voltage under which utility units have to operate under system contingency conditions. The result is a higher potential for grid instability.

Additionally, IPPs do not have the same "obligation to serve" that the utility does, and their performance is not subject to regulatory review. IPPs generally will make decisions on whether or not to provide capacity or energy based on economics, and not on the potential impact of their decisions on the utility's customers. When customers experience a service interruption that is based on a shortfall of generation, the customers look to the utility, not the IPP, as the cause.

Shifting the obligation to serve to IPPs would be difficult, if not impossible under current regulatory schemes. In general, absent regulatory restructuring, a utility would not be able to "assign" its obligation to serve and, thus, be relieved of this duty. The Commission may or may not be able to impose obligations on non-utilities as a condition for approving certain contracts, but the obligations would contractual, and not a result of the non-utility's status. (PURPA and state law specifically exclude certain forms of utility-type regulation for QFs and non-fossil fuel producers. Also, the Commission has found that IPPs that sell solely to utilities are not utilities themselves.) Additionally, as a practical matter, the imposition of utility obligations on power producers and/or broad requirements that such power producers indemnify utilities for their inability to fulfill their obligation to serve may render projects unfinanceable.

Although PPAs are written with care and are improved upon with every new PPA that is negotiated, every PPA is subject to interpretation. The IPP will interpret the contract to its advantage, which can lead to disputes, which can be costly to resolve.

A utility has much more flexibility to adjust to changed circumstances if it owns and operates it own units, than if it purchases power under long-term PPAs. PPAs cannot be drafted to provide for all future contingencies and changed circumstances, especially when they cover contract periods in excess of twenty years.

When building and operating its own unit, the utility can make changes in the operation of the unit and can modify the unit when appropriate, which cannot necessarily be done with purchased power under a PPA. For example, the utility generally will have more flexibility to accelerate or defer the in-service dates of its own units and to change the manner in which its own units are operated, and to adjust the maintenance schedules and the manning of its own units.

In the case of a change that requires the amendment of a PPA, the approval of the amendment generally will have to be negotiated with the IPP's owners (which may be a partnership or limited partnership), the IPP's lenders (which may be a group of lenders), and possibly even with certain suppliers under long-term contracts with the IPP; all of whom are represented by counsel.[1]

The interests of the utility, its customers and its shareholders are aligned because the utility's goal is to provide reliable service at the lowest reasonable cost to its customers while still earning a fair return on investment, based on the risks assumed in investing in the plant and rate base necessary to provide such service. The utility's decision to make or not make changes in its operations or facilities to adjust to changing circumstances would be subject to Commission review.

An IPP's decision to reject a request to change its PPA would not be subject to Commission review. Thus, the success of negotiations to amend a PPA will depend on the terms of the PPA and the economic impact of the modifications on the individual interests of the entities with an interest in a PPA, not the benefit of the amendment to the utility's customers.

The PPA's inherent lack of flexibility becomes magnified as the term of the contract is extended. This occurs because the assumptions used in negotiating the PPA become less precise as the period being forecasted increases. To the extent that these assumptions do not accurately predict future circumstances, any inflexibility inherently caused by the legal obligation of a long-term contract or by specific contract terms based on those set of assumptions would tend to be magnified.

The ability of an IPP to respond to the utility's needs would be governed by the terms and conditions of the PPA. The only way to provide the PPA with flexibility to adjust to all potential changed circumstances would be to grant the utility the right to act unilaterally to serve its own interests, provided that the facility was not damaged by the utility's actions. To the extent that an IPP is unwilling to grant the utility such rights under a PPA, the utility's flexibility would be diminished.

Project failure, termination of a project, or poor operating performance could be particularly detrimental in Hawaii since back-up resources are not readily available. Since the utility will still have the obligation to serve, project failures could be detrimental from both a reliability and cost standpoint.

Hawaii's experience with IPP reliability underscores these concerns. An IPP in Hawaii has experienced over three times the number of unit trips during a four-year period as one of the utilities operating nearly identical (but older) units. See HECO Response to PUC-IR-5. Additionally, other Hawaii IPPs have experienced long term deratings, undergone bankruptcy, or contributed directly to 8 of 9 rolling blackouts in one year. See response to HREA-HECO-IR-9.

[1] These approvals are in addition to approval from the Commission, which may also apply to changes in utility facilities requiring capital expenditures.

More stringent contract provisions such as higher security levels, clearly defined milestone schedules and associated damages if milestones are not adhered to, and other financial disincentives have been applied as solutions to mitigate this problem in other jursidictions. On the Mainland, access to security allows the utility to replace the contracted power through market purchases and the application of liquidated damages to make the utility's customers whole.

However, in Hawaii, even with stringent contract provisions and penalties for failure to perform under the contract, there is still the potential for an IPP to default on its obligation and incur the penalties. If the IPP cancels the project, the costs to customers could be much greater than the contract penalties alone if system reliability is jeopardized. At the end of the day, customers need electricity and contractual penalties paid by an IPP to the utility cannot replicate that. While liquidated damages could be included in the contract, such provisions may discourage bidders or lead to higher priced bids to compensate for the risk.

In addition to more stringent contract provisions, HECO has suggested that parallel planning may be another option to mitigate risk, particularly given the isolated nature of our island utility systems. Under this option, HECO could continue to proceed with a self-build option until it is highly certain that the awarded project will meet its commercial operation date. The costs for such parallel planning would be recovered by HECO, and would need to be considered as part of the overall cost to provide reliable power to customers. Such increase in the overall cost of power development may offset any hoped for cost savings benefit that competitive bidding is perceived to provide. HECO's response in PUC-IR-16 clearly underscores the significant costs that parallel planning entails.

Another possible option to potentially mitigate the reliability risk to customers is to allow HECO the option to buy the awarded bidders project if the bidder defaults on the contract. However, some of the practical challenges with this option include that the entity financing the project normally has first lien rights on the asset in case of default, relegating the purchasing utility to a lesser second lien position on the project.

The cost, practicality and potential unintended consequences of any candidate mitigation measure must be examined much more closely in the context of the small, isolated utility systems that exist in Hawaii before firm conclusions and recommendations can be reached on their effectiveness in any potential competitive bidding process.

2. **The development and implementation of an effective competitive bidding process can be very time consuming**

An effective competitive bidding process can take a substantial amount of time to develop and implement. A three to four year time horizon from development of the competitive bidding procedures to development and issuance of the RFP, and to negotiation and approval of a contract with a selected bidder is not unusual. This limits the flexibility of the host utility to solicit for resources quickly if requirements change. It should be noted, however, that current IRP process and negotiations/discussions for unsolicited QF proposals are time consuming as well.

It took nearly two years to develop the bidding rules in Oregon, from initiation of the case through a series of workshops to the establishment of rules. Recently, Louisiana initiated a proceeding to deal with market test rules for new generation. The Commission asked the Staff to open a Docket in December 2001. An Order was issued in the case establishing the rules in January 2004, more that two years later. The experiences in other states have been similar, particularly in cases where the new bidding rules have to be integrated with existing statutes.

The time required to undertake a competitive bidding process can be lengthy as well. Portland General Electric filed its Integrated Resource Plan in August 2002 and its draft RFP in April 2003. The RFP was issued in June 2003. Contract negotiations were recently completed (December 2004). In another recent RFP case, the Georgia Public Service Commission issued new bidding rules through a revision of the IRP rules in Georgia. Georgia Power and Savannah Electric are expected to issue RFPs for power supplies in January of 2005. According to the schedule identified by the Commission staff, the process is expected to take nearly two years from issuance of the RFP until Commission approval of the contracts resulting from the process. Furthermore, this schedule does not even include the time required to develop the RFP for the first solicitation process.

Because of the length of time needed to develop and implement a well-designed competitive bidding process, certain utility capacity addition projects already under development should not be subject to the competitive bidding process. For example, HECO currently has an urgent need for firm generating capacity. Please refer to HECO's Adequacy of Supply report, filed with the PUC on March 10, 2005. Efforts to install a simple cycle peaking unit at Campbell Industrial Park have been under way since early 2003. Although the capacity to be provided by the unit is needed now, the unit is not expected to be installed sooner than 2009, because of the long lead time for environmental review, permitting and approvals, equipment procurement and construction. It would not be practical for this unit to be subject to competitive bidding, because a well-designed and effective competitive bidding process cannot be put into place and completed soon enough. Based on the experiences in other states, it may take two years or more to develop the bidding rules. Once the rules are established, it may take two years or more to prepare an RFP, solicit proposals, evaluate the proposal, select the winning bidder and negotiate a contract. It could then take another seven years for the utility to obtain approval of the contract, and the selected bidder to obtain the necessary permits, procure the necessary equipment, and construct the unit. The unit would not be installed until several years beyond 2009.

On Maui, MECO is already procuring equipment for Maalaea Unit M18, which is scheduled for commercial operation in 2006. It would not be practical to subject this unit to a competitive bidding process as development of the project is well under way. In addition, MECO is already undertaking the permitting process for the first increment of firm generating capacity at its Waena site (Waena Unit 1), which is scheduled for installation in the 2010 timeframe. The unit may be needed sooner if the actual peak reduction benefits of MECO's proposed load management demand-side management ("DSM") and Combined Heat and Power ("CHP") projects are significantly lower than forecasted. Please refer to MECO's Adequacy of Supply report, filed with the PUC on March 15, 2005. It would not be practical to subject this unit to competitive bidding, because of the length of time it would take for bidding rules to be established and for the actual competitive bidding process to take place.

On the Island of Hawaii, Keahole Unit ST-7 is scheduled for installation in 2009 or sooner. Permitting efforts are already under way pursuant to a Settlement Agreement. It would not be practical to subject this unit to competitive bidding because of the length of time it would take for bidding rules to be established and for the actual competitive bidding process to take place.

3. **The resource commitment and cost to the host utility and regulators to undertake a competitive bidding process can be very substantial**

The development and implementation of a competitive bidding program will require significant resources of the host utility and can be expensive to implement. For example, in undertaking a competitive bidding process, utilities generally establish several internal project teams for the price analysis, non-price analysis and contract negotiations. This usually requires several analysts to undertake the pricing assessment as well as representatives from a number of departments within the Company to undertake the non-price analysis (e.g. financial analysis, environmental analysis, fuels, engineering, transmission system analysis, operations, siting/land, and legal). If the utility is proposing a self-build option, available resources may be further limited to protect confidentiality or outside resources may be required. In any case, the cost and commitment of resources is significant. Small utilities, such as HECO, may be particularly constrained in their ability to dedicate the appropriate amount of resources to adequately staff the project teams required. In other words, while the utilities employ personnel with the specialized skills and experience necessary to undertake the tasks described above, there are <u>not enough</u> of these people to divide into the specific functions needed to carry out bidding and evaluation responsibilities, while at the same time being excluded from carrying out their planning and evaluation responsibilities with respect to the utility's own projects. Such a resource problem has existed even for larger utilities, such as Portland General Electric, which presented a challenge for dedicating the required level of staff to the process.

Also, in some cases the utility is required to select an Independent Observer to observe or review the bidding process. This cost could be quite high as well. For example, it was reported in a recent bidding process on the mainland that the cost of the Independent Observer exceeded $500,000. HECO's competitive bidding consultant is aware of another competitive bidding process where the cost of the Independent Observer was approximately $1 million.

One of the lessons learned in undertaking a competitive bidding process for the first time is that the utility generally underestimates the resources, time required to undertake the RFP process, and the cost for undertaking the process, particularly the bid evaluation and contract negotiation phases.

The development and administration of competitive bidding processes will also place a significant burden on the Public Utilities Commission (PUC) and its staff, and the Consumer Advocate and its staff, to monitor and review the process, in addition to reviewing and approving the outcome of the process.

4. Implementation of a competitive bidding process can result in elimination of certain resources that may be favored from a public policy perspective

A strict implementation of competitive bidding may result in the elimination of less economical but publicly desirable resources competing on an equal footing with more economic options. For example, in many jurisdictions gas-fired combined cycle plants have been the lowest cost options in most RFP processes due to the low capital cost costs of these units, efficient heat rates, standardized unit design, flexibility in operations and shorter lead-time for development. Renewable projects such as wind, photovoltaics, biomass and landfill gas, and even other fossil fuel technologies such as coal, have had difficulty competing against gas-fired combined cycle projects in an all supply source RFP. Bidding programs designed to enhance the benefits of one resource relative to another may be contrary to the intent of the competitive bidding process and may result in a conflict with other public policy goals.

5. While mainland competitive bidding processes provide valuable models, one size does not fit all

The needs of isolated utility systems in Hawaii are significantly different from the utility systems on the mainland, which could influence the design and development of a competitive bidding process and the associated rules and guidelines. In many areas of the U.S. mainland, utility systems are part of a larger regional market, which provides utilities with access to a range of power supply options and products and reduces reliability risk. (In a number of instances, these include existing merchant plants.) In these systems, failure of the supplier to deliver could result in the buyer being indemnified based on the financial penalties contained in the power purchase agreement. The financial nature of the contract provides the utility the opportunity to purchase replacement power at market prices. The seller has to compensate the utility the difference between the contract price and the market price. The utility is made financially whole and still has access to reliable power supplies in the broader market.

In an isolated power market such as Hawaii, the inability to procure other sources of power could be devastating. There is no "broader market" from which replacement power could be obtained. The utility needs the physical power to meet customer reliability requirements. It is irrelevant if the utility is made financially whole.

Furthermore, purchased power already plays a significant role in the power market in Hawaii. The impact of additional purchased power on the reliability and operating flexibility of the power system in Hawaii would have to be addressed in any competitive bidding process.

To gain a better perspective on the unique nature of the Hawaiian electric system relative to mainland systems, the major characteristics of each system are contrasted below.

- Given the interconnected nature of utilities in many regions of the mainland, product and resource diversity is generally greater and a portfolio of resource options, contract terms, and product types is more likely. By contrast, it is expected that the number of options in Hawaii will be limited to new, long-term resource options. Resource and contract diversity options may also be more limited since options such as merchant generation, short-term contracts with marketers, and flexible products are not available in Hawaii. Suppliers will not build excess capacity and will insist on long-term contracts since there is no alternative market for the power. While suppliers on the mainland could offer a shorter-term contact and wheel the power to a broader market after the contract terminates, this option is not reasonable in Hawaii, with no alternative market. Suppliers have a limited outlet and, therefore, will seek longer term contracts. The utility will also need assurance of a long-term source of supply, especially given the long lead time needed for development or replacement resources.

- Given the size of the utility systems on each Island and the expected level of load growth, the amount of capacity required via a competitive bidding process is likely to be for a smaller amount of capacity than is traditionally required on the mainland, where it is not uncommon for utilities to request between 500 and 1,000 MW per solicitation. As a result, there may be fewer competitors to supply the power required, since most project developers prefer to construct larger units (as development costs are usually similar no matter the size of the project). Also, since economies of scale are common with larger projects, developers prefer to construct larger units and spread the development costs over more megawatts.

- Unlike mainland systems, there are no transmission interconnections between islands that allow for larger scale projects and broader market access. As a result, each island will have its unique needs and will place different values on resource options.

- HECO already relies on non-utility generation to meet a significant portion of its power supply requirements. This indicates that a viable non-utility market is already effectively present. Also, the financial impacts on the utility's balance sheet associated with increased purchased power costs will likely be more of a financial risk to HECO than most mainland utilities with a lower reliance on long-term purchased power arrangements. The percentage of firm capacity provided by IPP's on HECO's system rose to approximately 25% today, and is expected to increase to about 26% once Amendment Nos. 5 and 6 to the Kalaeloa amended PPA become effective. The percentage of HECO's baseloaded capacity provided by IPP's is even higher – about 35% assuming Kalaeloa provides 209 MW.

- The power purchase contracts between HECO and independent generators are long-term in nature and are exclusive with HECO, leading to long-term risk to the buyer. In fact, HECO is one utility that has already been required by rating agencies to rebalance its balance sheet by adding more equity to offset inferred debt from long-term purchased power agreements.

- System reliability and resource availability are very important in Hawaii given the isolated nature of the utility system in Hawaii. Contract provisions will need to reflect this requirement. The reliability of specific generation resources in interconnected systems may not be as important as in isolated systems. Power contracts have become more focused on financial arrangements with liquidated damages paid to the buyer in case of default designed to keep the buyer financially whole. As a result, if a seller defaults, the buyer merely collects the damages and buys the make-up power in the market. For utilities in Hawaii, contract provisions will be more stringent, and financial damages will not make the utility and its customers "whole" if generation shortfalls result.

- By the nature of the island energy system, fuel options are more limited in Hawaii than on the mainland. In particular, there are no natural gas sources, unlike on most mainland systems where natural gas-fired projects dominate. Also, on the mainland, many utilities are offering gas tolling options to power generators[2], thereby absorbing the fuel risk. This is possible since the utility may also have a portfolio of gas supply contracts and transportation arrangements.

- The unique operational characteristics associated with the electric system in Hawaii would have to be accounted for in any competitive bidding process. These include the unique considerations and operational aspects of isolated utility system (i.e., plant size limitations, quick start capability, spinning reserves, quick-load pick-up capability, minimum load requirements, reliability requirements, cycling requirements, redundancy, frequency and voltage control, system frequency bias, and other factors), load growth uncertainty, land use restrictions, and permitting requirements.

[2] In such a tolling arrangement, the utility purchases and supplies the fuel.

- Economies of scale and scope are more important competitive factors in the mainland markets and the development schedule will likely be much shorter than in Hawaii.

- Due to the nature of the power system in Hawaii with no outside interconnections and available options, HECO may be required to undertake a parallel planning process in case a selected project fails.

- Capacity installation costs are higher in Hawaii. The costs of developing new generating resources in Hawaii that can meet the unique requirements to operate in a non-interconnected island grid are invariably underestimated by those relying upon cost estimates for similar resources to be installed on the mainland. Moreover, the costs tend to be site-specific. Only the developers with acquired sites would be able to submit realistic bids, and those who bid based on mainland-derived cost estimates (who might well be the low bidders) would not be able to finance or build their proposed projects.

6. Competitive Bidding and procurement of power resources through IPP power purchase agreements may reduce the utility's ability to manage the unique grid requirements of isolated utility systems

Contractual arrangements for the purchase of power may sometimes constrain the flexibility to manage system issues that evolve over time. Modifications to generating units needed to meet new operating requirements, such as cycling on and off or being operated at lower load levels, may be difficult to obtain. Project financing agreements may limit the ability of the IPP to agree to modifications, even if the utility compensates the IPP for making the modifications.

7. Competitive bidding and procurement through independent power purchase agreements may reduce utility and regulatory control over utility system operations.

The PUC cannot exercise the same level of regulatory control over IPPs that it has over the utility. In particular, the PUC does not generally have access to the financial information of IPPs or control over their profitability to ensure that the utility system customers receive an adequate benefit for the power being purchased. As the level of power purchased from IPPs increases, the PUC must increase reliance on the utility's ability to manage the IPP performance through the terms and conditions of its contracts.

8. Various forms of competition already exist that can achieve the goals of competitive bidding

IPPs already have the opportunity to propose projects that can deliver power at less than the costs of the utility's alternatives. This is evidenced by the fact that there are already significant IPP levels of penetration on the HECO systems.

The utilities already use competitive bidding processes for equipment and service procurement to ensure cost management.

Utility customers are continuously looking for ways to reduce costs. Competitive alternatives already exist from many kinds of self-generation (distributed) resource providers, including renewable technologies such as photovoltaics, fuel cells, and combined heat and power (CHP) facilities.

Issue 2: Whether a competitive bidding system should be developed for acquiring or building new generation in Hawaii?

HECO/HELCO/MECO Position:

A. HECO has Concerns with Competitive Bidding

HECO has reservations about the effectiveness of competitive bidding in an island system such as Hawaii. If competitive bidding is implemented, there are a number of potential shortcomings or pitfalls that need to be addressed to ensure that a competitive bidding system provides benefits to customers and shareholders. HECO can appreciate some of the potential benefits of competitive bidding but supports the implementation of competitive bidding only if the process is designed in such a way that the benefits occur instead of the pitfalls.

B. Potential Shortcomings of Competitive Bidding that Need to be Addressed

The following are the potential pitfalls or shortcomings that need to be satisfactorily addressed:

1. **The time allotted for developing and implementing a competitive bidding process must be adequate to ensure all the key potential pitfalls and shortcomings are appropriately addressed. While the process can be time consuming, HECO advocates taking the necessary time up-front to effectively design the rules and guidelines necessary to implement the competitive bidding process including the power purchase contracts**

   The development and implementation of a competitive bidding process can be a very time consuming process, generally taking several years to complete. However, taking the time necessary to effectively develop the process in the early stages serves to avoid the potential for very costly mistakes and potential delays later in the process.

   There are several approaches for instituting competitive bidding as evidenced by the experiences in other states:

   (1) A common approach followed by a number of states is to adopt the rules and guidelines for competitive bidding first through a formal regulatory process (e.g. Competitive Bidding Docket), prior to initiation of the actual competitive solicitation. Under this approach, the soliciting utility and bidders know the rules and guidelines and the process is implemented based on these guidelines. In a number of jurisdictions, the bidding guidelines were integrated with the state statutes underlying how jurisdictional utilities are regulated in the state.

   (2) Another approach is to develop the bidding procedures and RFP via a collaborative process, with input from a number of parties. One of the disadvantages of collaborative processes is that they tend to take longer and often result in less than optimum compromises to resolve issues put forth by special

interest groups. However, collaborative processes could be used whether formal bidding rules are in place or not. For example, the Oregon Public Utilities Commission established the bidding rules in 1991. The recent Portland General RFP process followed the bidding rules but the IRP and RFP were undertaken via a collaborative type process.

(3) A third approach is for the soliciting utility to independently develop and issue an RFP when it needs power and evaluate the bids when received. The rules and guidelines for the process are established in the RFP, generally without input from outside entities.

There are trade-offs associated with each approach. In the last approach, the utility has the discretion to carry out the bidding process and select the appropriate proposal. This approach can be implemented quickly when the need arises. However, it is possible that bidder complaints and problems will arise because certain bidders may claim they were not being fairly treated or the process was biased toward a specific type of bidder or project structure. It is not uncommon for one or more bidders to file complaints with the public utility commission if a bidder loses or feels it needs additional time to complete its proposal.

The approach based on the establishment of bidding rules and guidelines followed by the issuance of an RFP has been more common. Bidding rules and guidelines exist in a number of states and other states are in the process of implementing such rules. (Please refer to Exhibit E of the HECO Companies Preliminary Statement of Position for the Competitive Bidding Status By State.) This approach also provides clearer signals to bidders and others in terms of the specific rules of the game and the guidelines under which the competitive bidding process will be conducted. With clear rules in place, there should be fewer complaints by bidders and less uncertainty about the process. While this approach may limit flexibility in terms of adjusting to changing market conditions, the guidelines could be developed to offer some opportunity to adjust the process to conform to required changes.

Although this approach can be time consuming, it is important to spend the needed time up-front in the development of the bidding rules and guidelines (and the integration with the IRP framework) to address the potential shortcomings and pitfalls of a competitive bidding process and avoid difficulties later on. As noted before, it is not uncommon for the process from development of the bidding guidelines to implementation of the competitive bidding process to take several years. In addition, this process will require significant regulatory involvement throughout the process.

One of the major complexities often overlooked in competitive bidding processes is the development of the power purchase agreements which ultimately specify the terms and conditions of products and services being bid. Power purchase contracts developed prior to the bidding process can help to organize and structure the process by specifying the terms and conditions to which all bidders must conform. A major difficulty is developing a contract document that can accommodate varying types of technologies and performance criteria. For example, firm power purchase contracts must have many more specific performance and enforcement provisions than as-available energy contracts.

HECO's position is that the process to develop an effective and fair competitive bidding process will be time consuming. However, it is important that sufficient time be allocated to ensure the process is adequately developed and potential pitfalls and shortcomings can be discussed and resolved.

2. The host utility as a primary stakeholder must play a major role in the competitive bidding process

The host utility should play a major role in the competitive bidding process including: (1) designing the RFP documents, evaluation criteria, and power purchase agreement; (2) managing the RFP process, including communications with bidders; (3) evaluating the bids received; (4) selecting the bids based on the established criteria; (5) negotiating contracts with selected bidders; and (6) competing in the solicitation process with a self-build option, if feasible.

The above mentioned roles for the host utility are common in most RFP processes and are recognized by regulators and third-party bidders as a reasonable role for the host utility. Recent competitive bidding dockets have recognized the role of the utility and have supported an active role for the host utility. In fact, in several RFP processes, utility self-build or turnkey options have been the successful bidders among a large number of options, including recent Portland General Electric, PacifiCorp and Florida Power & Light RFP processes.

The goal of any competitive bidding process is to encourage and evaluate a range of generation options with the objective of obtaining the best possible option for the customers of the utility. This goal can only be assured if all resource options are allowed to compete. Regulatory commissions have recognized that a utility project may be the lowest cost option and failure to allow that option to compete may result in higher cost power options, contrary to their goals and objectives.

In two recent competitive bidding proposals, these issues were clearly addressed. The Staff Report and Recommendations prepared by the Staff of the Louisiana Public Service Commission in Docket No. R-26172 (Development of Market-Based Mechanisms to Evaluate Proposals to Construct or Acquire Generating Capacity to Meet Native Load), March 13, 2002, clearly stated its objectives in considering the competitive bidding process.

> As many of the comments correctly recognize, the utilities have an obligation to serve and provide reliable service. They also have an obligation to do so at lowest reasonable cost. This rulemaking does not change those basic principles. Given this obligation, along with episodic problems in recent years associated with

> wholesale market supply (e.g. price spikes, shortages), the self-build option cannot be "taken off the table" in deference to the market. Moreover, the maintenance of a self-build option for utilities will help serve to discipline and restrain the market in the intermediate and long run. (Page 4)

Comments of bidders regarding utility participation in the RFP process were summarized in the Order:

> Most commenters, however, recognized that utility projects may be appropriate if they pass a market test. As Sempra's witness states, the purpose of the RFP process is to "get the best deal for ratepayers in terms of cost, risks, reliability and environmental performance". It is possible that a utility self-build project -- vetted through an RFP -- could be the "best deal for ratepayers." (Page 3 of Commission Order)

In its Order, the Louisiana Public Service Commission identified the role of the utility in the competitive bidding process as follows:

> After providing an opportunity for review, analysis and comment on the planning data and the draft RFP, the utility will proceed with the issuance of the RFP and review of the bids received. Staff and qualifying participants (those entitled to review the confidential bids) will have an opportunity to review the bids and the utility's evaluation analysis of those bids. Based upon the RFP results and its evaluation, the utility may choose to proceed with its self-build option or enter into contract negotiations with one or more bidders (or both). Staff (and qualified participants) will have the opportunity to provide input on the utility's bid evaluation and resource selection. (Page 5 of the Commission's Order, Feb. 16, 2004)

Likewise, the Staff Report prepared by the Staff of the Arizona Public Service Commission (Competitive Solicitation Docket NOS E-00000A-02-0051 ET AL), October 25, 2002 concluded:

> The utility will be responsible for preparing the solicitation and conducting the solicitation process. Acquisition of energy and capacity to meet the needs of customers remains the responsibility of the utility, and the utility shall use accepted business standards for acquiring these resources, as it does when it buys all other products used in providing service. (Page 8)

In other recent RFP processes, self-build options have been allowed and encouraged. For example, the Oregon Public Utility Commission allowed Portland General to offer a self-build option as a result of a revision to its 1991 competitive bidding rules, which stated that utility self-build options were not eligible to bid. Portland General had to submit its proposal to the Commission in advance of receipt of other bids and had to provide the same information required of other bidders.

The bidding rules in Quebec allow Hydro-Quebec Generation to bid into the Distribution Company's Call for Tenders process as long as everyone abides by the same rules. The Generation Company has been awarded contacts but other independent power producers have been successful bidders as well.

Furthermore, the utility possesses the models and methodologies to undertake the most comprehensive evaluation of the bids received, and also significant knowledge and information regarding its system and customers. This information and capability ensures that the most detailed and comprehensive analysis can be undertaken.

With regard to host utility self-build options, as previously noted, utilities have been selecting their own build options more frequently over the past few years for several reasons. Please refer to Response to HREA-HECO-IR-10 for specific examples of utilities selecting self-build options. First, the financial and credit problems faced by independent generators have led to higher debt costs and higher equity ratios for independent generators, virtually eliminating the competitive advantage once enjoyed by independent generators. Utility projects are now competitive from a financial perspective. Second, transmission constraints in a number of markets have led to higher transmission costs for resources located outside the utility service area or in costly transmission areas. Third, the deteriorating credit quality of many independent generators has raised concern over counter-party reliability. In turn, power purchase agreements require higher levels of security and tighter damage provisions to protect the utility's customers against the prospect of contract default. There is heightened concern that independent generators are less reliable that host utilities in developing and operating their projects.

3. **The competitive bidding process should take into account all costs associated with each bid to ensure all bids are fairly and equitably evaluated**

For a competitive bidding process to be fair and equitable, all relevant costs should be recognized for each bid, in addition to the direct cost of the bid itself. This includes the transmission costs and system impacts associated with each project, **system operational impacts**, and the impacts of purchased power on the utility's balance sheet.

Including the impacts on the transmission system for each bid (or each short-listed bid) is common in most RFPs. Utilities generally conduct interconnection studies that assess the direct cost of interconnecting the plant to the utility system as well as the cost of any transmission system upgrades to effectuate delivery of power to the customers. In several recent RFPs, these costs have been significant and a major influence on the relative ranking of each bid.

The impact of each bid on system operations can be addressed through a system-wide evaluation which considers the impact of each bid based on the operating flexibility included in the proposal. The economic evaluation can be based on the system-wide net present value revenue requirements for each resource plan or portfolio with the bids included in each plan. For example, if a bidder offers dispatchability of its unit, the avoided costs or incremental costs associated with unit dispatch can be calculated and included in system-wide costs. Likewise, if a project is bid as a "must run" unit, the impacts of that operational mode on system costs should be calculated and included in the evaluation. In this case, if the project is designed to operate whenever it is available, it may displace lower fuel cost units or result in other units being dispatched off-line or not operating. These units may be required to provide voltage support or other system benefits that now are more costly to provide or result in unintended system constraints.

Another important cost component and one that is gaining attention on the mainland is the impact of purchased power costs on the utilities' balance sheets and the potential for utility credit downgrades (and higher borrowing costs) as a result.

Basically, rating agencies treat the fixed payments associated with power purchase agreements as debt on the utility's balance sheet since the utility has incurred an obligation to make a stream of fixed payments to the seller over the life of the contract. Imputing or including the cost of purchased power as debt has the potential of adversely affecting a utility's capital structure and its interest coverage ratios due to this increased risk. A corresponding increase in the equity of the utility may be required to rebalance the capital structure and this cost needs to be accounted for in evaluating power purchase agreements. Because the cost of equity exceeds the cost of debt, this rebalancing of the utility's capital structure to accommodate the additional financial leverage of purchased power contracts imposes additional costs that must be considered in any economic evaluation of alternatives. As a result, while purchased power commitments do not involve direct capital investment, they do have financial implications that must be considered to allow for a meaningful comparison between supply alternatives.

While recent accounting rules have affirmed how such costs should be treated, it is important to note that the HECO Companies have already been required by the credit rating agencies to rebalance their capital structures as a result of their purchased power commitments. The HECO Companies have had to add higher cost equity capital to balance the imputed debt attributed to existing non-utility power purchase agreements.

In 2003, the United States Emerging Issues Task Force (EITF) reached a consensus on EITF Issue 01-8 whereby "arrangements or contracts that traditionally have not been viewed as leases may contain features that would require them to be accounted for as leases under Financial Accounting Standard 13, Accounting for Leases". Examples of arrangements that may fall under these rules include power purchase agreements. Under these rules, if the purchased power agreement meets the tests included in EITF 01-8 for lease accounting and the tests for a capital lease included in FAS 13 the transaction is explicitly recorded as a debt obligation on the utility's balance sheet. The accounting for capital lease obligations is not a discretionary issue and as noted the HECO Companies have had to abide by these rules. Please refer to Exhibit C of the HECO Companies Preliminary Statement of Position for a detailed discussion of the accounting issues.

Several states have approved the inclusion of direct or imputed debt associated with purchased power commitments in the evaluation of resource options. For example, Florida utilities have included an equity adjustment in their RFP process. Also, the Florida Public Service Commission has acknowledged that an equity adjustment is appropriate to address the capital structure impacts associated with purchase power arrangements and it is reasonable to consider the financial impacts of purchased power. The Florida Commission determined that purchased power contracts imply higher debt leverage, and that the costs of rebalancing the capital structure to accommodate this debt should be considered in determining payments for purchased power. Other states such as Wisconsin, Utah, California, and Oregon have recently raised the issue for consideration of resource options. The Wisconsin Public Service Commission concluded that the utility must be compensated for the adverse impact on its capitalization associated with capital lease obligations arising from purchased power transactions.

The California Public Utilities Commission stated in Decision 04-12-048 (Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning, December 16, 2004):

> Debt Equivalence is a real cost that needs to be considered when evaluating bids from a PPA vs. a utility-owned resource. As SDG&E states, "[I]t is essentially undisputed that the credit analysts treat the utilities' long-term non-debt obligations, such as PPAs, as if they are in fact debt when they assess a utility's debt capacity." Consequently, the IOUs should take into account the impact of Debt Equivalence when evaluating individual bids in an all-source and RPS RFO, regardless of whether it is a fossil, renewable, or an existing QF resource. (Page 144)

Based on the HECO Companies' already significant commitment to purchased power and the requirement already imposed on the company to rebalance its balance sheet as a result of these obligations, imputed debt and direct debt issues must be addressed in the development of the RFP process and an equity adjustment should be included in the evaluation of bids received, which warrant such treatment, along with the inclusion of transmission-related costs and operations-related costs for each bid.

4. The timeframe for the evaluation should reflect the life of a power plant to ensure that all options are compared on the same consistent basis

It is anticipated that the most likely bidders in Hawaii will be project developers proposing to construct and operate a new power generation facility to meet the power needs of the HECO Companies. As a result, all or most options will be for long-term power contracts, reflecting the life of the plant or term of financing. The life of a power plant (whether a utility plant or independent power project) is generally in excess of 30 years.

In their evaluation of IPP proposals, the HECO Companies have assumed 25 to 30 year lives for both IPP-owned and utility-owned central station generating units. As a practical matter, however, the usefulness of such facilities generally continues after the expiration of the depreciation-life period, if the facilities are well maintained.

This issue highlights a difference, however, between utility plants and IPP projects. While a utility plant may have a life exceeding 40 years, once the plant is fully depreciated, the costs recovered from customers generally are limited to operating costs[3], including fuel, O&M, taxes, and other related costs. On the other hand, an IPP would have the opportunity to sell its power at the end of the contract term at whatever price the market could bear. The IPP, however, is not limited in its cost recovery to only operating costs.

One option to address this concern is to specify that the host utility has the right to buy the project from the bidder for $1 or some estimated salvage value at the end of the contract term. Bidders will be required to structure their bid price around the pre-specified buyout price.

A second option is to require the bidder to sell its power beyond the term of the contract, at the buyers' option, at an extension of the terms of the contract in place at the termination of the contract. This would involve extending the pricing terms out several years based on the pricing formula in place at the termination of the contract.

5. **The HECO Companies propose that a wide range of supply-side options be eligible to bid including power purchase arrangements, utility self-build options and turnkey arrangements (i.e., build and transfer option). HECO recommends that the RFP process be open to only supply-side resources, with DSM options not eligible to bid, and with Combined Heat and Power (CHP) projects worked through a competitive procurement process.**

Recent RFP processes have allowed a variety of supply-side options to compete. For example, in the Portland General Electric RFP, power purchase agreements, fully or partially completed merchant plants sales options, utility self-build, turnkey arrangements, renewable resources, short-term forward contracts, virtual tolling arrangements, and options contracts were eligible. The HECO Companies support broad eligibility for this process as well. Bidders will also be eligible to offer multiple contract structures if they so choose.

In conjunction with the inclusion of credit quality and financial impacts in the evaluation of power purchase agreements, the option for a turnkey project provides the correct signals for the bidder to structure its project recognizing the value of the project structure. For example, if bidders are concerned that a straight power purchase agreement will not

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[3] Some capital costs may be incurred for refurbishment projects resulting in betterment.

be competitive if financial impacts are accounted for during the evaluation, the bidder will also have the option to offer a turnkey arrangement as well.

With regard to DSM and CHP, it is important to recognize that these resources are very different from traditional supply-side resources and should not become subject to the same evaluation process. In the past, in some cases the industry attempted to evaluate DSM and supply-side resources using the same evaluation criteria and RFP. However, these processes proved to be flawed because the resources are inherently different and require separate RFPs, evaluation criteria, and contracts. The industry standard over the past bidding cycle (e.g. since the late 1990's) has been to conduct supply-side only solicitations, rather than all-source solicitations. DSM RFPs have not been common recently.

For CHP resources, the Companies plan to use a competitive procurement process. The objectives of the competitive procurement process are, among others, (1) to ensure provision of quality CHP products and services, (2) to standardize equipment and designs, (3) to achieve efficiency in the equipment selection process, and (4) to obtain cost savings for the utility and its ratepayers, especially over the life cycle of the CHP installation. Please refer to HECO's Opening Brief in the Proceeding to Investigate Distributed Generation in Hawaii, Docket No. 03-0371, filed on March 7, 2005, Section I.D.1., pages 22 to 24.

6. **The value of flexibility should be built into the competitive bidding process**

Many utility competitive bidding processes recognize the value of flexibility in the evaluation of resource alternatives. Such flexibility options as contract buy-out options, project in-service date deferral or acceleration provisions, or project acquisition options are valuable options for a utility to more effectively balance its needs with the cost of obtaining such options. With the utilization of option pricing concepts in the mid-1990's in the utility industry, a number of utilities developed the procedures and models to evaluate such options in their competitive bidding processes. Bidders were required to competitively bid such options and the host utility was able to quantify such an option. HECO views such flexibility as an important criterion for the evaluation of the bids received.

Given the nature of their Island systems, the HECO Companies are also concerned about fuel flexibility and the option to convert to an alternative fuel if fuel cost or availability changes dramatically. Over a 30 year contract life, there is no way of knowing if new technologies will emerge over time that could reduce fuel costs. While non-price evaluation criteria could be included in the evaluation process, HECO prefers to include a more direct option in the RFP process to provide HECO the option to request conversion of the plant to an alternate fuel if conditions warrant, with appropriate modifications to the PPA to account for the bidder/seller's conversion costs and to pass on the benefit of the lower fuel costs.

7. **The timing of implementation of any competitive bidding process needs to consider the timing of system needs**

   Given the time that it takes to develop and implement competitive bidding processes, it will be necessary to exempt certain near-term facilities from these processes to future units to allow for near-term needs to be met in a timely manner. (See earlier discussion.) HECO also suggests that the competitive bidding process should not be required for defined capacity needs of 25 MW or less and the expansion or repowering of existing company units. Please refer to HECO Response to PUC-IR-40.

C. Conclusion

In conclusion, HECO has reservations about the applicability of competitive bidding to an island system such as Hawaii. HECO has a number of concerns regarding the potential shortcomings of a competitive bidding process that should be addressed in the design, development and implementation of a competitive bidding program. Without resolution of these issues HECO could not support the institution of competitive bidding for acquiring or building new resources in Hawaii.

<u>Issue 2a</u>: How can a fair competitive bidding system be developed that ensures that competitive benefits result from the system and ratepayers are not placed at undue risk?

<u>HECO/HELCO/MECO Position:</u>

Competitive bidding processes are very complex and require an assessment of a number of factors to ensure a balance between encouraging competitive benefits and providing customers with the best resource options while ensuring reliability. Developing a fair and competitive bidding system requires an identification of the characteristics of successful competitive bidding processes that have effectively addressed fairness and bias issues. To address these considerations, it is important to assess the characteristics of successful bidding processes to establish the parameters for developing such a system and to also consider some of the recent lessons learned in other competitive bidding processes to provide some guidance in the development of such a process.

A. Characteristics of Successful Competitive Bidding Processes

There are a number of characteristics of a successful competitive bidding process that can serve as a basis for developing such a process if the Commission decides to pursue competitive bidding.

1. **The competitive bidding process should be fair and equitable to all bidders.**

   The competitive bidding process should allow for the flexibility to make adjustments as necessary to ensure these criteria are met. All bidders should be treated the same in terms of access to information, time of receipt of information, and response to questions. One mechanism for ensuring bidders have access to information is for the utility to develop a website where it can post documents and information for bidders to access. Bidders should have a general knowledge of the bid evaluation and selection process. This generally involves an identification of the criteria of importance to the utility in the RFP document. The bidder can then reflect these criteria in its bid.

2. **The solicitation process should ensure that competitive benefits for utility customers and stakeholders result from the process.**

   A well-designed competitive bidding process should provide competitive benefits for both utility customers and shareholders. Customers can benefit through lower costs for power driven by competition. Shareholders benefit through lower regulatory risk involving the utility's ability to recover all reasonable costs. An effective competitive bidding process should serve both purposes. An effective competitive bidding process should encourage lower prices with an appropriate balance of risk and account for all reasonable costs in the evaluation process.

   As noted in response to Issue 2, all reasonable costs should be validated in the evaluation process for either all the bids received or a short-list of bids based on the number of bids received. The balance between cost and risk can also be addressed by including a model power purchase agreement in the RFP document. This allows bidders the opportunity to review and assess the contract provisions of importance to the host utility and reflect these terms in its price. The contract terms proposed by the HECO Companies will need to reflect the value of reliability of power supply on a system such as an Island utility system.

3. **The competitive bidding process should be designed to encourage broad participation from potential bidders.**

To ensure that all reasonable options are effectively considered, there should be no unreasonable restrictions on sizes and types of projects. It is generally preferable that all types of eligible projects (e.g. supply-side options) have a fair opportunity to compete. This will ensure that all eligible resource options are considered in the selection process, and a lowest cost resource plan can ultimately be developed. It is not always reasonable to establish a target number of bids as a basis for success because the size and diversity of the market may influence the amount of bidders and capacity bid.

Another issue is the type and form of threshold criteria to apply for the competitive bidding process. Stringent threshold criteria (i.e. bidder has to have site control, maintain a certain credit rating, demonstrate the technology used is mature, have identified all environmental permits, etc.) are generally applied when the market is not very mature and the risk of project failure is great. Lenient threshold criteria are generally applied in a mature market or a case where market access to other resources is easy in case of project failure. HECO expects that more stringent threshold criteria will be necessary for the island systems since the risk of project failure can be significant for utility customers. Thus, it is important that bids received have been in the development process for a reasonable amount of time.

4. **The Request for Proposal document (i.e. the RFP, Response Package, and Power Contracts) should describe the bidding guidelines, the bidding requirements to guide bidders in preparing and submitting their proposals, the bid evaluation and selection criteria, and the risk factors important to the utility.**

The above referenced information identifies the important requirements of the utility and places bidders on an equivalent basis. This objective can be met through a well-designed RFP that provides details on the process and defines bidder requirements. It is not necessary for this solicitation process to be a transparent, self-scoring system to meet this objective. Transparent processes, while more bidder-friendly, create gaming opportunities and lead to more complaints and a more contentious process. Self-scoring systems are not the norm. Solicitation processes that provide adequate information on the requirements of the purchasing utility, provide clear and concise information to bidders on the requirements for completing their proposal, and identify in sufficient detail the evaluation and selection criteria are consistent with this overall objective.

One of the major challenges in the design and development of the RFP process is to ensure the RFP document, response package (information requested of bidders to allow the utility to evaluate the bids relative to the criteria established) and power purchase agreement are closely aligned and integrated. It is common that a change in one document leads to changes in other documents as well and such tracking is necessary to avoid inconsistent signals to bidders.

5. **The solicitation process should include thorough, consistent and accurate information on which to evaluate bids, a consistent and equitable evaluation process, documentation of decisions, and guidelines for undertaking the solicitation process.**

   In this regard, it is important that bids are evaluated based on a consistent and thorough set of information provided by the bidder, the utility, and outside independent sources. The RFP should require bidders to provide information consistent with the evaluation criteria to ensure that the important attributes of each proposal can be equitably and fairly evaluated. For example, in order to assess whether the capacity proposed by bidders can in fact be built, each bidder's proposal needs to contain information regarding the bidder's control of the site upon which the capacity will be built, and the technology to be installed, as well as information upon which an assessment of the permittability of the unit can be made. The forecasts and other information provided by the utility should include outside sources as well as system specific information. The solicitation and evaluation process should also ensure that the results of the evaluation process can be fully documented.

6. **The solicitation process should ensure that the power purchase agreement is designed to minimize risk to utility customers and shareholders while providing a reasonable opportunity to finance the project.**

   It is not in the best interest of the host utility if the evaluation process selects a project but that project cannot secure financing because of onerous terms in the contract. At the same time, contracts that could lead to significant risk to the utility and its customers are also not in the best interests of these parties and could lead to serious financial implications. As a result, it is important that the contract provides a proper balance of risks between buyer and seller, with each party incurring the risks it is most capable of managing. In the HECO Companies' case, the contract provisions have to reflect the nature of an island utility system.

   In most cases, the utility will include a copy of the model power contract in the RFP (or multiple copies if different types of resources are expected to bid). While utilities will identify certain terms and provisions that may not be negotiable, usually the bidder has the opportunity to raise exceptions to the contract and the utility can gauge whether or not such exceptions are reasonable or could lead to a fatal flaw in negotiations. In most cases, the utility does not have to accept the exceptions taken by the bidder.

7. **The solicitation process should incorporate the unique aspects of the utility system and the preferences and requirements of the utility and its customers.**

   Each utility system is unique in terms of its existing resource mix, customer profile, transmission and locational issues, regulatory requirements, operational considerations and customer preferences. These unique aspects of the utility system must therefore be addressed in the design of the solicitation process. As a result, the evaluation criteria should reflect the factors of importance to the utility customers and shareholders. Reflecting utility specific preferences in the design of the solicitation process is an important aspect of an effective solicitation process.

   <u>This is particularly important for an island system, where attributes such as quick load pick-up for proposed units, spinning reserves, redundancy criteria, ramp rates and load following capability, dispatchability, and other operational flexibility attributes are important, and should be required of bidders.</u>

B. Lessons Learned in Recent Competitive Bidding Processes

Competitive bidding processes are evolving with the changes in the power market. The following points describe some of the recent trends and initiatives with regard to competitive bidding processes and the implications of these initiatives for guidance in the design and development of an effective competitive bidding process.

1. It is important to establish the "rules of the game" before undertaking a competitive bidding process. Bidders prefer to know before undertaking the development of a proposal "how the winner will be selected". Establishing the ground rules up-front to allow bidders and other stakeholders the opportunity to consider all factors before deciding to participate is important to ensure a successful process. Poorer, more contentious competitive bidding processes result from the development and implementation of a competitive bidding process without the consideration and resolution of a number of key issues that could influence the process.

2. Due to the financial crisis in the electric generation industry, credit quality of the counterparty is now one of the most important evaluation criteria in competitive bidding processes.

3. Integrated evaluation systems using sophisticated production cost and generation planning models for bid evaluation are the norm in the industry. These models allow the utility to capture the cost and operational impacts on its system based on the individual proposal or portfolio of proposals.

4. Price-related evaluation criteria are the predominant selection criteria. Non-price criteria are used to ensure the project or portfolio is viable and feasible but price is usually the ultimate determinant.

5. Recent credit problems of some independent generators have generally led to higher equity ratios and higher debt costs for IPPs.

6. Recent bidding rules and guidelines recognize the value of allowing all options to compete, including utility projects and turnkey arrangements.

7. Utility projects are more economic relative to IPPs and have been successful in several solicitations.

8. Supply-side and DSM RFPs are generally undertaken as separate processes, not as an all-source process due to the unique nature of the resources.

9. The failure rate of projects is a significant factor. It is important to realize that not all projects awarded a contract will succeed and not all projects that win a bid will end up successfully negotiating a contract. This issue has become more prominent since the financial condition of the counterparty can lead to decisions by IPPs to terminate a project, even one with the possibility for a long-term power contract. Power generators in poor financial health may be required by their lenders to direct available capital to other projects.

10. Power contracting has become much more complex and time consuming due to the more stringent contract terms required of utilities as a result of the increased risk associated with financially challenged power generators and the desire of the power generators to avoid absorbing this risk.

11. In more RFP processes, all system costs are being included in the analysis, including transmission costs and system operations costs.

12. The time, cost, and resource commitment necessary to carry out a competitive bidding process can be significant, with a timeframe from initiation of RFP design to contract negotiation lasting up to two years. This lengthy time requirement can also discourage bidders from holding their price open for this long of a period.

13. Some utilities are taking on the fuel supply function for IPPs through tolling arrangements.

14. Transmission costs (i.e. interconnection costs, system upgrades required to facilitate delivery of power, and direct transmission costs) are having an impact on distinguishing projects.

15. The impacts of direct and imputed debt as a component of the bid evaluation process are being recognized by a number of regulatory commissions and utilities as an important factor in evaluating and selecting resource options.

<u>Issue 2b:</u> What are the specific competitive bidding guidelines and requirements for prospective bidders, including the evaluation system to be used and the process for evaluation and selection?

<u>HECO/HELCO/MECO Position:</u>

The guiding principles which underlie the HECO Companies' initial position on a potential competitive bidding process include the following:

1. The bidding rules and guidelines must address the unique nature of the electric utility system in Hawaii relative to mainland systems.

2. The bidding rules and guidelines should recognize the significant role already played by independent power generators in the Hawaii electric market.

3. As previously noted, the development of competitive bidding rules and guidelines should be developed from the ground up without superimposing another state's system directly in Hawaii.

4. The development of competitive bidding rules and guidelines should identify and address potential shortcomings associated with the development of such a system, including the timing requirements necessary for developing the appropriate structure, the process for integrating the RFP with the IRP process, the role of the utility as a major stakeholder in the process, consistent treatment for all options, which reflects the true cost of the power to the utility's customers, and a reflection of the operational considerations and costs associated with each resource option.

   In complex processes such as a competitive bidding framework, the "devil is in the details" and merely establishing a general framework as the CA and HREA have recommended in their SOP's or immediately proceeding to develop an RFP or PPA are not adequate and will likely lead to negative implications for competitive bidding, including the possibility for protracted litigation if bidders feel the rules changed or they were treated unfairly during the process.

   The HECO Companies disagree with the Consumer Advocate's position that a competitive bidding process can proceed based on "industry best practices" that are developed for each RFP on a case-by-case basis. Please refer to CA Response to HECO/CA-IR-4. Although in principle the HECO Companies agree with the CA that different types of competitive solicitations may warrant different guidelines (and by extension, that a certain amount of flexibility in the guidelines is preferable to rigid guidelines that unnecessarily limit RFP development and bidder responses), the CA's proposal is too open ended. First, no consensus "industry best practices" appear to have emerged. Rather, practices vary from jurisdiction to jurisdiction. Second, well thought out guidelines developed in advance of a specific solicitation will allow opportunities for review and comment by all interested parties. Guidelines based on "industry best practices" that first appear in a specific RFP are likely to foster complaints by potential bidders and may act as a bar to bidders. If concerns proved significant enough, they might slow or even stop the RFP process until issues could be resolved. Third, of even greater concern to the HECO Companies is the possibility that their performance during the competitive bidding process, especially in terms of developing "industry best practices" for a specific RFP, would be evaluated after the fact, thereby denying the utilities the opportunity to "cure" potential problems. Besides being inefficient, such "Monday morning quarterbacking" is unfair to all participants in the process, particularly to the host utility that might be subject to complaints and litigation alleging that the "best practices" unduly favored the host utility or affiliate or unduly burdened other bidders.

Should the bidding rules be developed and put in place, the HECO Companies recommend that the first RFP process be undertaken in conjunction with the next IRP process. As noted in the response to Issue 3, the HECO Companies recommend that the IRP be used to identify the timing and amount of resource requirements along with the preferred resource or resources. The RFP will then be used to fill that need based on actual market options.

Once this process is initiated, the HECO Companies propose a multiple stage process to implement the competitive bidding process. The stages of such a multi-stage process, and the major tasks and issues that generally would be included in each stage, are described below:

Stage 1: Develop the RFP

There are several components of this task. These include addressing the key policy issues associated with the RFP design and development. Some of these issues may be addressed in the establishment of rules and guidelines underlying the competitive bidding process. Some of the key issues that must be addressed at this stage include:

- Resolve any issues associated with the role of bidding in the IRP process. As explained in the discussion of Issue 3 (What revisions should be made to the integrated resources planning process?) below , HECO advocates integrating the IRP and RFP process, with the IRP used to define the amount of capacity to solicit and the timing of need.

- Determine the type of bidding process to implement. HECO supports a multi-stage evaluation system that includes threshold, price and non-price evaluation criteria. HECO, however, proposes to use a price-driven process as the basis for selection of the preferred resources. (Under such approach, the utility subjects all proposals to the threshold criteria, then organizes or clusters bids that pass the threshold criteria by type of resource (i.e. wind bids, combined cycles and combustion turbines will be evaluated together) and subjects all proposals to a price screen and non-price analysis. Price and non-price points are determined for each proposal within the cluster. The best projects within each cluster (from a price and non-price perspective) are included on the short list. Generally, all proposals on the short list are considered viable and feasible projects. The final evaluation is based on determining the option or portfolio of options which result in the lowest net present value revenue requirements for the overall resource plan.)

- Determine bidder eligibility. As previously noted, the HECO Companies generally support an all supply source RFP (including conventional supply-side resources and renewable technologies) with eligibility including independent power projects, utility self-build option, and turnkey arrangements. HECO does not support all source bidding given the complexities of including DSM in the bid evaluation and selection process.

- Establish the price evaluation methodology. HECO proposes to undertake a detailed system evaluation process using the same models and methodologies used for the IRP process. The RFP will contain the data required of bidders in their proposals for undertaking the analysis. The bids would be evaluated over a time horizon that takes into account the expected lives of generating facilities.

- Identify the price and non-price criteria and the weights associated with each general criterion. For the non-price factors, such characteristics as development feasibility (site status, environmental permitting, financial plan, critical path, etc), operational viability (O&M plan, fuel supply plan, etc.), operational requirements (i.e. dispatchability, ramp rates, spinning reserves, load following capability, etc.), and flexibility (i.e. contract buyout options, fuel conversion option) should be included.

- Establish the role of the utility in the RFP process and any safeguards required. As noted, consistent with the majority of RFP processes, HECO supports an active role for the host utility in every phase of the RFP process. This includes development of the RFP, evaluation of bids and selection of the short-list, and development and preparation of the utility's self-build option. Procedures would be developed prior to initiation of the bidding process to define the roles of the members of the various project teams, outline the communication process with bidders, and to address confidentiality of the information provided by bidders.

- Establish credit requirements and security provisions. These components have become more important based on the financial condition of a number of power generators and the risk and cost of project failure. In RFPs dealing with isolated systems or island systems, the security requirements included have been fairly stringent. For example, the recent BC Hydro Call for Tenders for power on Vancouver Island contained fairly stringent security requirements to ensure well financed bidders would compete and to discourage bidders from defaulting on the contract or terminating their project.

- Develop the model Power Purchase Agreement. As previously noted, contract issues are becoming more complex and new provisions are being included in the contract. Provisions addressing liquidated damages, flexibility options (buyout or delay provisions, fuel conversion provisions, etc.), asset transfer arrangements, and other matters have to be included. Existing PPAs would be used as the starting point, but additional provisions generally included in more recent contracts resulting from competitive bid processes could also be included.

- Assess the appropriate methodology for evaluating the impacts of purchased power in the bid evaluation process. This is a very important factor for utilities with significant purchased power obligations such as HECO.

- Establish the operational parameters required (or preferred) of units bid into the RFP, including dispatchability, minimum turndown, ramp rates, and other performance criteria as may be applicable to the specific technology. Ideally, these requirements should be consistent with the utility's own requirements.

- Develop the methodology necessary for conducting the transmission cost assessment. Decide if the utility will conduct interconnection studies on behalf of or for bidders.

Other issues which must be considered in Stage 1 include the following:

- Development of an internal implementation schedule with the tasks and manpower requirements for undertaking the RFP process;

- Development of the evaluation criteria and weights, generally through an iterative process;

- Development of a procedures manual which describes the documentation process, reporting requirements, organizational structure, communications requirements, etc.;

- Development of the model Power Purchase Arrangements;

- Prepare draft of the RFP and response package;

- Develop database for documenting the bid evaluation and scoring process;

- Develop a website for communication with bidders;

- "Stress Test" the evaluation system using hypothetical bids; and

- Incorporate revisions to the RFP.

In total, this Phase of the process could take approximately 6 months from initiation of the RFP development phase. The process could take substantially longer if prior approval of the RFP is required, which HECO does not recommend.

Stage 2: Issue the RFP/Bid Preparation

Stage 2 activities involve the period from issuance of the RFP to receipt of bids. An important aspect of Stage 2 is the marketing of the RFP. It is typical for utilities to announce the issuance of the RFP through the trade press as well as notifying potential bidders that have expressed an interest in bidding. Utilities now generally post the RFP on the Company's established RFP website with information guiding the potential bidder. This process ensures that potential bidders have access to the RFP and any related materials.

It is also common in this stage for the host utility to conduct a Bidders Conference. The Bidders Conference generally allows bidders the opportunity to attend a presentation by the utility conducting the RFP and ask questions about the RFP and the bidding process. Again, this provides bidders the opportunity to seek and receive information about the process in preparation for their bid.

Most RFP processes request that bidders complete and submit a Notice of Intent to Bid form to the host utility. This provides an indicator to the host utility about the number of potential bidders. Once the Notice of Intent is filed, bidders are either provided a password to access information about the RFP process, including responses to questions, any addendum, and other information or have unfettered access via the host utility's website.

The last major activity at this stage of the process is the response by the host utility to bidders' questions. The responses to questions provided on the host utility's website are generally considered the official response of the utility and ensures that a consistent response is provided. This eliminates the possibility that someone within the Company may provide an unofficial answer which can influence the decisions of the bidder. The official response can reflect the input of a number of staff and management personnel with the host utility to ensure the official answer is provided.

The bid preparation process generally takes 3-4 months even if potential bidders are aware of the process in advance. Bidders generally start committing serious money to the bid preparation process after they have reviewed and studied the RFP.

Stage 3: Evaluation of Bids

Stage 3 is a major step in the process. For the bid evaluation, most utilities utilize a multi-stage process designed to eventually reduce the bids down to a selected few or what is commonly called the award group. A proposed evaluation process will be described below in some detail. The multi-stage evaluation process generally includes: (1) receipt of the proposals; (2) completeness check; (3) threshold or minimum requirements evaluation; (4) initial evaluation including price screen/non-price assessment; (5) selection of the short list; (6) detailed evaluation or portfolio development; (7) select award group for contract negotiation; and (8) management (and sometimes board) approval of the contract(s).

The first step in this stage of the process is the receipt of proposals. Generally when bids are received they are date stamped and organized and in most cases coded by number or letter. The proposals are generally maintained in a secure area to limit access to the bids to only those authorized members of the project team. This process ensures that competitive information is not distributed to any unauthorized individual. Bids are either disseminated to members of the project team or team members have to review the bids in a central secure location.

The initial review of the proposals includes a completeness check to ensure all the relevant information is provided with each bid and all bids can then be evaluated using an organized, structured process.

Bids that do not provide all the information requested could be rejected and the proposal returned to the bidder. In some RFP processes, the host utility may submit clarification questions to bidders if the information presented in not complete or clear. These questions are generally issued only when the request for clarification or information does not jeopardize the competitive nature of the process.

Bids that are deemed complete are then subject to the threshold criteria stage of the process. The threshold or minimum requirements evaluation is designed to ensure that bidders have met some minimum standards with regards to the development of their projects. Bids which fail to meet the established minimum requirements will be subject to rejection. The threshold or minimum requirements will be identified in the RFP so that bidders will clearly know the standards that must be met for qualifying for the evaluation of the bids.

Bids that meet the threshold or minimum requirements are then generally subject to an initial evaluation. At this stage it is common for utilities to segregate bids into different technologies or categories and conduct a price screening analysis of all bids as well as a non-price evaluation. The methodology used for the price screen phase could be real levelized cost analysis or an internal model designed to conduct an initial assessment of bids.

On the mainland, a separate project team may conduct a detailed non-price evaluation of the bids relative to the non-price evaluation criteria selected. There are a number of possible approaches for ranking bids at this stage. First, a common approach is to combine price and non-price points based on a pre-established weighting system and rank the bids based on points. The highest ranked bids in each category would then be subject to the detailed price or portfolio evaluation. The intent is to select bids that are both low cost and are viable projects (bids which have a high likelihood of success). A second option used is to conduct a pass/fail assessment of each bid relative to the non-price criteria. Bids that "pass" at this stage are included in the final evaluation.

The result of this stage of the bid evaluation process is a selection of a short-list of bids that will be considered in the final evaluation. On the mainland, the short-list often includes two to three times the amount of capacity required in the RFP to ensure several portfolios can be developed and evaluated. In many cases, system costs associated with transmission impacts, inferred debt impacts, and system operational factors can be taken into consideration.

Based on the detailed or portfolio analysis, the preferred resources can be selected based on their total system cost impact. It is common practice for a host utility to select a winning bid as well as a back-up in case the preferred bid fails or is not able to negotiate a contract.

The final step in the process is generally a board or senior management presentation detailing the basis for selection of the winning bid followed by Board or senior management approval.

This process can take at least 4 months and depends on the number of bids received.

Stage 4: Contract Negotiations

As previously noted, the contract negotiation process is becoming more complex and time consuming due to the poorer credit quality of a number of power generators, the requirements of the banks involved in project financing, and the requirements of the purchasing utility. There have been several recent examples of bidders agreeing to the major contract provisions outlined in the utility's model power purchase agreement and then reneging on these requirements during the contract negotiation process. For example, Hydro-Quebec Distribution Company's first Call for Tenders included specific security requirements in both the Call for Tenders document and the model power purchase agreement. The winning bidder agreed to these requirements when it submitted its proposal. However, two months into the contract negotiation process, the bidder decided it could not accept the security provisions. Hydro-Quebec then terminated negotiations and had to initiate contract negotiations with the back-up bidder, effectively delaying the process by more than two months. This is not uncommon in the industry today in cases where the bidder is under no penalty if it decides to terminate negotiations or cancel the project. In a recent Call for Tenders involving BC Hydro, the utility included strict provisions in the contract that severely penalized a bidder from terminating a project if it was selected as the winning bidder.

Nevertheless, there are several steps involved in the contract negotiation process. In many RFPs, bidders are provided a model power purchase agreement and have the opportunity to list exceptions to the contract. The utility has the option of agreeing to these exceptions. However, the exceptions at least provide the utility with a base of knowledge to begin contract negotiations.

The utility also has to organize the contract negotiation team. The team generally consists of a lead attorney, a credit specialist, a commercial specialist, and possibly a system operations specialist. Negotiation of credit terms has become a very important aspect of the contract negotiation process over the past few years.

It is not uncommon for the contract negotiation process to take from 3-12 months. Contract negotiations in the recent Portland General RFP process took nearly 12 months to complete. To avoid such protracted delay, some utilities will establish a time limit for contract negotiations (i.e. 2 to 3 months) and specify the limit in the RFP document. The utility has the right to terminate negotiations and move on to the next bidder if a contract is not completed or substantially completed within that timeframe. This ensures the utility does not face reliability problems if a bidder negotiates for several months, terminates the project, and the utility has no other alternatives. This is particularly problematic in a utility system such as Hawaii.

During contract negotiations, senior management will be informed of the status of the negotiations process. Negotiations are not complete until the management (and sometimes the board] of the utility (and likely the developer as well) have agreed to all terms and conditions prior to submission of the contract for regulatory approval.

Stage 5: Regulatory Approvals

In many states, the Commission has to either approve the resulting power contract or grant a certificate of need if a self-build option or turnkey arrangement is awarded the contract. This can also be a time consuming process depending on the other commitments of the Commission and the presence of any major intervenors.

<u>Issue 2c:</u> How can a fair competitive bidding system encourage broad participation from a range of prospective bidders?

The HECO Companies caution that the response to a competitive bidding process in Hawaii will likely not achieve the same level of activity as on the mainland. This is due to the smaller capacity requirements in Hawaii, the lack of merchant plants seeking power contracts, lack of short-term options, and more limited market access. In addition, development costs are likely to be higher and economies of scale are not significant.

While there is no guarantee that a competitive bidding process in Hawaii will generate a broad range of bids from a number of suppliers, the design of a fair and equitable bidding process will likely generate more interest from bidders. In deciding whether or not to bid and the type of product to propose, a bidder has to assess its chance of winning relative to the cost of developing and submitting a bid. If a bidder expects the process to be a fair and competitive process and if he understands the ground rules, the bidder can make a more informed decision.

Some of the ways for the host utility to encourage broad participation from a range of prospective bidders include:

- Clearly inform bidders of the requirements for bidding. The RFP should provide substantial details on the bidding process and the requirements for submitting a proposal. Therefore, bidders will know the rules of the game before developing a proposal.

- Provide guidance to bidders regarding the basis for "winning the bid". Bidders all want to know how they can win the bid. This involves providing a description of the bid evaluation and selection process in the RFP.

- The development of bidding guidelines and rules up-front provide guidance to bidders and ensure the process is not likely to continually change or evolve through the bidding process. One problem in some RFP processes that discourage bidders is a change or multiple changes in schedule. Bidders prefer a degree of certainty in the process. The Hydro-Quebec Call for Tenders process has been viewed favorably by the bidders because the process has been consistent and on schedule. Bidders know the rules of the game and that Hydro-Quebec will follow the rules as defined.

- Include reasonably transparent evaluation criteria that inform bidders of the criteria of importance to the utility. In most RFPs, utilities will identify the general evaluation criteria with an indication of the weights for each criterion. The utility will then develop an evaluation methodology designed to allocate points or scores for each criterion that are used by the utility's bid evaluation team in the bid evaluation process.

- Including a model power purchase agreement in the RFP document provides valuable information to bidders deciding whether or not to bid and what level of risk is required. Bidders can then reflect that risk in their proposal.

- In some RFP processes, an Independent Observer is retained by the utility (in some cases with the approval of the Commission) to observe and/or audit the bid evaluation and selection process. The utility conducts the evaluation of the bids and is responsible for selecting the winners and negotiating contracts. If an Independent Observer is requested, HECO recommends that the role of the Independent Observer be to manage correspondence between the utility and bidders, review and audit the results of the evaluation process, and advise the utility if there are any fairness issues.

  In order to be effective, Independent Observers should have a demonstrated track record of impartiality, be able to work effectively with the utility over the long term, be able to report candidly to the Commission, and be knowledgeable about the unique characteristics and needs of the small, non-interconnected island electric grids

  If an Independent Observer is required, the Independent Observer selected should meet certain criteria, including:

    - Be familiar with island utility systems and be aware of the unique challenges and operational requirements of such systems.

    - Have the necessary experience and familiarity with utility modeling capability, transmission system planning, operational characteristics, and other factors that affect project selection.

    - Have the capability of working with the utility during the evaluation process.

  HECO could identify potential candidate consulting firms to serve as the Independent Observer and accept candidates provided by the Commission as well. HECO could ask the Commission to review the list and approve the list of candidates. HECO could then issue and RFP for consulting services from candidates on the list and select the consultant that meets the criteria established.

- Establish a website for communicating with prospective bidders that ensures all bidders receive information about the process at the same time.

There are a number of examples of recent RFPs that highlight these points. For example, the Portland General Electric RFP was developed within the bidding guidelines in Oregon. Portland General conducted several workshops for potential bidders and provided draft copies of the RFP. The RFP clearly identified the requirements of bidders, including providing a bid form or response package that identified the information requested of bidders as well as the criteria of importance and their general weights. The eligibility requirements of the RFP were very broad including conventional supply-side options, potential ownership options from existing or partially completed merchant generation facilities, renewable resources, and an identified self-build option. Portland General included general information about its self-build option in the RFP including the technology selected, estimated overnight capital costs, heat rate information, etc. Portland General also included several model power purchase agreements based on the different products requested. Portland General received over 100 proposals for a broad range of products from a variety of bidders.

Portland General also retained an independent third-party observer to validate that the scoring criteria did not inappropriately bias the process in favor of equity investment by Portland General.

<u>Issue 3:</u> What revisions should be made to the integrated resource planning process?

HECO proposes that the IRP and RFP processes become integrated. Hawaii has a well established integrated resource planning process in place that would need to be revised to accommodate competitive bidding. In many jurisdictions, utilities have used the IRP process to provide strategic direction to the long-term resource acquisition process. The IRP has been used to determine the portfolio strategy of the utility (i.e. level of renewable resources desired, fuel diversity requirements, environmental attributes, etc.), identify the timing and amount of capacity needs, and the preferred technologies or resources based on an assessment of the estimated costs of potential resource options. The results and findings from the IRP process can provide the necessary inputs to the development and implementation of the RFP. Thus, in many jurisdictions, there is a close linkage between the IRP process and the RFP.

HECO believes the two processes should be integrated and it is necessary to decide on the appropriate integration option before competitive bidding is implemented in Hawaii.

Of the several options for integrating the IRP and RFP processes, the HECO Companies recommend adopting the most common approach, which is to implement the competitive bidding process after the IRP process is initiated and a preliminary "preferred" plan is developed (see Figure 1). The IRP can be performed using the current process followed by HECO. In this case, the role of the IRP is to identify the preliminary "preferred" resource plan, define capacity and energy requirements, the timing of need, any preferred technologies, and potentially any other preferred attributes. The IRP can also be used to identify any preferences or criteria for resource selection and can be used to determine avoided costs.

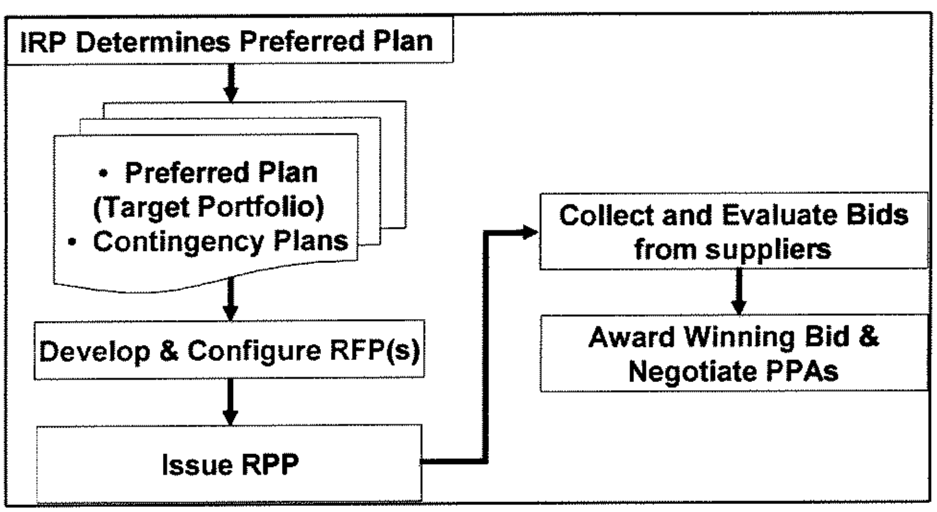

Figure 1: Preliminary IRP Followed by RFP Process and Resource Selection

In this model, the role of the RFP includes the solicitation and evaluation of resource options to meet the capacity and energy needs identified in the preliminary resource plan. The RFP can be used to solicit bids for either a block of resources as defined in the IRP or for the next required resource identified in the IRP. Bidders are allowed to submit proposals for any variety of resource types and sizes. The utility also has the right to submit proposals for resources that may differ from the preferred resource type included in the preliminary resource plan. The bids received in response to the RFP are evaluated relative to one another and/or to the avoided costs of the generic resource identified in the IRP or to the utility self-build project. The IRP establishes the parameters for the RFP. After the bids are evaluated and the preferred resource selected, the utility will then build the resource (if a self-build option is selected), or negotiate a turnkey contract or power purchase agreement (PPA) with the winning bidder (if a turnkey or PPA option is selected). HECO will essentially develop its preferred resource plan after the bids are received. The final bid(s) selected will be part of the final Integrated Resource Plan.

The advantages of this approach are that the final Integrated Resource Plan is developed after the bids are received and evaluated, and the resulting resource(s) has been subjected to a competitive market test. Also, this approach allows for the opportunity to develop a portfolio of projects to include in the final resource plan.

One drawback is that developers may not want to bid resources identified as preferred in the later years of the resource plan, because they do not represent current business opportunities, which would limit the validation of cost estimates by market test. However, the utility will not want to irrevocably lock itself into commitments for resources that will not be needed for many years anyway.

In Hawaii, the preferred utility strategy is one that allows the utility to make major decisions regarding the implementation of program options (for both supply-side and demand-side resources) incrementally, based on the best available information at the time decisions must be made. The "Preferred" Plan is better characterized as a planning "strategy", rather than a fixed course of action. The plan identifies what information is critical to the decision making process, and also identifies when the strategic decision needs to be made. A critical element of the plan is the recognition that the planned generating additions can be altered as the utility pursues other options, including renewable technologies and additional cost-effective DSM programs. This planning strategy allows the development of alternate options to address alternate futures. In order to retain flexibility:

- IRP preliminary preferred plan would be created to provide a benchmark against which resources can be evaluated. The parameters established by the preliminary preferred plan would include capacity and energy requirements, the timing of need, any preferred technologies, and potentially any other preferred attributes. Resource plans would be compared using the resource-in/resource-out method, with the preferred plan as the basis. Refer to Appendix B in the HECO Companies Electric Utility System Cost System filing (Avoided Cost Methodology).

- An evaluation of bids submitted in a competitive bidding process may reveal that the most cost-effective unit is not necessarily a unit that is in the IRP preferred plan. Weight must be given to the factors that led to a particular resource being included in the preferred plan. For example, if a coal unit is in the preferred plan to provide a fuel diversity benefit even if it is not the most cost-effective resource, then the bid evaluation must give weight to resources that provide a fuel diversity benefit.

- The IRP preferred plan will define resources that were selected based on assumptions that were applicable at the time the plan was selected. However, actual conditions can deviate from the assumptions upon which the preferred plan was selected. Bids must be evaluated on the basis of actual conditions at the time the bids are evaluated.

- Bidding would be conducted for near-term needs, taking into account the time required to permit and install the resources.

Should competitive bidding be implemented in Hawaii, revisions to the Framework for Integrated Resource Planning may be appropriate to account for the integration of the RFP process with the IRP process. It would be premature to propose specific changes to the Framework before competitive bidding guidelines, if any, are adopted.

HECO and CA's preferred approach with regard to the integration of competitive bidding with the IRP framework are generally consistent. There are, however, a few differences. HECO does not support the CA's position that the resource identified as the preferred resource in the IRP would necessarily serve as the utility's contingency plan should the competitive bidding process be unsuccessful. HECO prefers to maintain the option for submitting a bid in response to the RFP and utilizing the time between the submission of the IRP and the date bids are due to refine the characteristics and pricing of its own resource option to ensure, among other things, that it includes the most up-to-date information available to provide the lowest reasonable cost option for the customers.[4] Also, HECO's preferred contingency plan may be different depending on the timing of IPP project failure. If an IPP project fails close to the time it is scheduled to go into service, HECO's only reasonable option may be to install emergency generators rather than its own project.

Also, HECO does not believe that the role of the Commission to resolve disputes between the utility and bidders or among bidders, as suggested by the CA, is an efficient or effective role for the Commission. Direct Commission involvement as a referee in the operations of the competitive bidding process will encourage bidders and others to frequently contact the Commission to favor their own cause and may jeopardize the fairness and objectivity of the competitive bidding process. For example, if a Commission staffer provides information to one bidder but not to another the integrity of the process can be compromised. HECO's recommended approach for conducting informational meetings with the Commission throughout the process could meet these objectives of the CA without placing the Commission in a direct day-to-day role in the process. HECO understands that in other processes where the Commission had a direct active role, it proved to be an invitation for bidders to contact the Commission to vent their concerns and attempt to achieve a more favorable result.

[4] See HECO Response to PUC-IR-34.

Finally, the CA is non-committal on the issue of whether the Commission should approve the RFP before it is issued. See CA's PSOP at page 49. HECO has now concluded that it is preferable that the Commission should not be involved in approving the RFP prior to issuance.

EXHIBIT II

Exhibit II

Competitive Bidding Guidelines
<u>(Assuming Competitive Bidding Is Implemented)</u>

This exhibit addresses the following subjects:

1. Implementation of competitive bidding (pages 2-5).

2. Competitive bidding exceptions (pages 5-11).

3. Utility's role in competitive bidding (pages 11-12).

4. "Fairness" issues, including

   (a) the use of an independent observer (pages 13-15),

   (b) a utility submitting a bid (pages 15-17),

   (c) transparency issues (pages 17-20),

   (d) utility staffing issues (pages 21-22),

   (e) the RFP review process (pages 22-24), and

   (f) the dispute resolution process (pages 24-25).

5. How the RFP process would work, including

   (a) the competitive bidding process (pages 25-26),

   (b) PPA terms/options (pages 26-29),

   (c) "turnkey" arrangements (page 29), and

   (d) evaluation/selection criteria (pages 29-34).

6. The integration of competitive bidding with other processes, including

   (a) IRP (pages 34-36), and

   (b) PURPA rules (pages 36-38).

1. Implementation Of Competitive Bidding

HECO

HECO's position is that the details of the competitive bidding process should be developed in a follow-up proceeding based on the principles enunciated by the Commission in this proceeding. Establishing a competitive bidding framework or guidelines is a preferable solution for all parties. Once the guidelines are established, "the rules of the game" for competitive bidding can be developed and will become clearer to all parties.

In essence, the Companies view a three-stage process - - in the first stage, basic guidelines are established; in the second stage, framework provisions (or agency rules) are established based on the guidelines; and in the third-stage, utility-specific provisions (RFP documents, process manuals, etc.) are developed in a manner consistent with the framework provisions (or rules). In the IRP framework proceeding, the first two stages were sequentially done in the same docket, because the parties were able to agree on guidelines for IRP in an initial stage of the docket.

The HECO Companies prefer that the procedures be developed and adopted in a framework proceeding, like that used to develop the IRP Framework, rather than in a rulemaking proceeding. HECO recommends guidelines over rules in order to provide for flexibility to adjust to different situations and circumstances. A good framework should be flexible enough to permit tailoring the process to the specific circumstances, yet specific enough to avoid after-the-fact determinations of fundamental process matters (e.g., whether the utility should have used separate utility project proposal and bid evaluation teams - - which generally would be impractical in Hawaii). This will provide flexibility, while helping to avoid attempts by losing bidders to undo a completed competitive bidding process (which would delay the addition of needed resources), no matter how fairly the bidding and evaluation process actually was conducted.

The advantage of guidelines is that they provide an indicator to bidders about the rules of the game and provide bidders a comfort level that the process will be undertaken in a fair and equitable manner. The disadvantage of developing a framework or rules is that the development (and implementation) of a competitive bidding process can be a very time consuming process, sometimes taking several years to complete.[1] However, taking the time necessary to effectively develop the process in the early stages serves to avoid the potential for very costly mistakes and potential delays later in the process.

In general, the Companies note that a good framework should be flexible enough to permit tailoring the process to the specific circumstances, yet specific enough to avoid after-the-fact determinations of fundamental process matters (e.g., whether the utility should

[1] In the case of Portland General in Oregon, which has been cited as a possible model, it took 28 months to adopt competitive bidding guidelines. In Hawaii, it took 28 months (from January 10, 1990 to May 22, 1992) to complete the proceeding in which the IRP Framework was adopted. However, that included the time required to develop collaborative principles. Rulemaking proceedings in Hawaii have taken a number of years to complete.

have used separate utility project proposal and bid evaluation teams - - which generally would be impractical in Hawaii). This will provide flexibility, while helping to avoid attempts by losing bidders to undo a completed competitive bidding process (which would delay the addition of needed resources), no matter how fairly the bidding and evaluation process actually was conducted.

HECO expects that many components of the RFP will not vary significantly from solicitation to solicitation. The general criteria, the steps involved in the evaluation process, the process for selecting a short-list of bidders, the questions or information requested of bidders, and the contract negotiation process will not vary significantly from one solicitation to the next unless a major change in the industry occurs. While some changes may be necessary for each solicitation, the basic structure, procedures, and processes will likely be consistent.

Should the bidding rules be developed and put in place, the HECO Companies recommend that the first RFP process be undertaken in conjunction with the next IRP process.

<u>The CA</u>

The CA contends that no new rules are required to implement competitive bidding.[2] Instead, the PUC should "avoid being prescriptive regarding how competitive bidding processes are to be conducted, and instead state clearly that utilities must adhere to 'best practices' . . . ." CA SOP at 4, 44, 55, 56-57.

The term best practices, as used by the CA, "is based on the fact that there is a substantial body of experience in the industry on methods of conducting competitive bidding for resources of various types. The utilities have access to the experience of others in the industry through discussions with utilities on consultants with experience in the bidding process to utilize bidding procedures that have be[sic] used to successfully conduct similar solicitations elsewhere." CA SOP at 55n.29.

According to the CA, the "utility would determine best practices by surveying and considering approaches taken by similarly-situated utilities in soliciting similar types of resources. Depending on circumstances, it also might be appropriate for the utility to seek advice from consultants and others within the industry who had expertise in the area of competitive bidding processes. Similarly, reports issued by those reviewing the implementation of solicitation processes also might serve as useful resources. Finally, implementation of best practices can be expected to require a measure of business acumen and common sense in identifying procedures likely to support fair, transparent solicitation processes." Response to HECO/CA-IR-4.c.

In the CA's view, the "utility will be responsible for employing practices that it can defend to stakeholders and the Commission, as appropriate." CA SOP at 55. The utility would have to be prepared to demonstrate, during and after each solicitation process, that they have met this requirement. CA SOP at 43-44.

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[2] CA SOP at 43. See response to PUC-IR-24.

The CA notes that the "appropriate approach to designing and implementing competitive bidding will vary depending on the utility and resources being procured", and competitive bidding design and implementation methods can be expected to improve with time and as the utilities gain experience." CA SOP at 55.

It is important that all participants in the process (i.e., potential bidders, the utility, customers, and other interested parties) understand the rules and guidelines underlying the competitive bidding process. In such complex processes, the "devil is in the details". It is not sufficient to merely pronounce general principles, as the CA (and HREA) have proposed in their SOPs, and then immediately proceed to develop an RFP. This could be a recipe for protracted litigation.

It is HECO's position that, to ensure benefits result from a competitive bidding process, adequate time should be taken upfront to develop and implement the process effectively rather than immediately implement a process "on the fly". A process that is not well planned and thought out is potentially subject to complaints and criticisms if the process fails. HECO's position is that the time required to develop an effective process may mean that the next round of resource needs may not be applicable for bidding.

It is in the best interest of all stakeholders if a solid foundation is established for bidding, if that is the desired objective from this proceeding. The trend in the industry is that most states that have implemented competitive bidding programs have done so based on the development of formal rules or guidelines. Some of these are flexible, but in all cases these processes prescribe more than just requiring utilities to follow a "best practices" approach.

The CA concludes that competitive bidding should be implemented in Hawaii and continually states that the process should be implemented based on the "best practices" from other successful competitive bidding programs on the mainland. However, the CA never defines what it classifies as "best practices". No two competitive bidding processes are exactly alike. Each process may have its pros and cons, and it is difficult to determine if one represents "best practice" and one does not.

It is HECO's experience that "best practices" for one group of stakeholders may not be "best practices" for another group. While HECO appreciates the CA's position that HECO and its consultants are in the best position to develop the process based on "best practices", HECO wants to avoid the prospect of "Monday Morning Quarterbacking" should the implementation of the process result in a decision different than some stakeholders expected. Whether the guidelines are formal rules, or flexible guidelines, it is important that some guidelines are at least defined before a competitive bidding process is implemented. Merely requiring that the competitive bidding process is based on "best practices" is not sufficient to achieve an effective competitive bidding process.

One very real concern is that "best practices" will be associated with "optimal practices if the utility has unlimited time and resources." For example, it would be easy to argue that no person involved in developing the utility-owned resource bid should be involved in evaluating the bids, or it could be argued that the utility should retain an "independent" third-party to evaluate the bids. Total separation is not a viable or preferable requirement given the resources of the Hawaii utilities. Delegating responsibility to a third-party to evaluate bids, who cannot possibly have the Hawaii specific knowledge and experience necessary to perform such a task, would be expensive and a recipe for disaster. Policy decisions regarding what the utility does not have to do in conducting a competitive bidding process are just as important as what the utility should do, and these types of policy decisions should be made upfront and included in appropriate guidelines. At the same time, the guidelines should include waiver provisions, so that timely adjustments can be made where the guidelines do not prove to be workable under particular circumstances.

2. Competitive Bidding Exceptions

HECO

Exceptions to any mandated competitive bidding process must be allowed when the competitive bidding process would not allow needed generation to be added in a timely fashion, and when another competitive procurement process would be more efficient.

Projects Under Development

Because of the length of time needed to develop and implement a well-designed competitive bidding process, and to permit and install new generation, certain utility capacity addition projects already under development should not be subject to the competitive bidding process. For example, HECO currently has an urgent need for firm generating capacity. Efforts to install a simple cycle peaking unit at Campbell Industrial Park have been under way since early 2003. Although the capacity to be provided by the unit is needed now, the unit is not expected to be installed sooner than 2009, because of the long lead time for environmental review, permitting and approvals, equipment procurement and construction. It would not be practical for this unit to be subject to competitive bidding, because a well-designed and effective competitive bidding process cannot be put into place and completed soon enough.[3]

As stated in Exhibit A to HECO's SOP, competitive bidding was not and should not be considered for HECO's simple cycle peaking unit at Campbell Industrial Park, MECO's Maalaea Unit Unit 18 and Waena Unit 1, and HELCO's Keahole Unit ST-7. See responses to

3 SOP, Exhibit A, pages 8-9. If an IPP-owned peaking unit was selected through a new competitive bidding process adopted as a result of this proceeding, the unit would not be installed until several years beyond 2009. This assumes that it could take 8 to 12 months to complete this proceeding, 12 to 24 months to approve a new competitive bidding process, 4 to 8 months to initially implement the process, and seven years or more to obtain environmental review of, and permits and approvals for, and to acquire the equipment for and install, the new generation. It would be imprudent to apply the new process to generation that has to be added earlier than the process could be completed, even if some form of "expedited" process was followed.
Based on the experiences in other states, it may take two years or more to develop the bidding rules. Once the rules are established, it may take two years or more to prepare an RFP, solicit proposals, evaluate the proposal, select the winning bidder and negotiate a contract. It could then take another seven years for the utility to obtain approval of the contract, and the selected bidder to obtain the necessary permits, procure the necessary equipment, and construct the unit.

CA-HECO-IR-13.b, PUC-IR-15.a. and PUC-IR-47. The status of these units is described in the response to PUC-IR-15.a. at 2-4.

With respect to Maalaea Unit 18, an alternative ownership option was considered impractical, as the installation of that unit will complete the conversion of MECO's existing simple cycle combustion turbines Maalaea Units 17 and 19 to a 2-on-1 combined cycle unit. The conversion requires that two heat recovery steam generators and a steam turbine-generator (Unit 18) be integrated with the existing Units 17 and 19. Unit 18 will be installed on MECO property and it is impractical to demarcate boundaries and associated responsibilities for all utility and non-utility facilities, including buildings, access lanes, laydown areas, and integrated piping, ductwork and wiring, if Unit 18 was to be non-utility owned. Moreover, non-utility ownership of Unit 18 would likely require duplication of utility and non-utility operational and maintenance staffs, resulting in higher overall operational expense and unwieldy complications in the coordination of work and schedules for the integrated combined cycle unit. However, although it is impractical for Unit 18 to be non-utility owned, all major equipment and construction services for Unit 18 will be procured through competitive bidding processes.

If, instead, a competitive bidding for new generation process were used to secure stand-alone replacement capacity that would otherwise be provided by utility installation of Unit 18, the conversion of Units 17 and 19 to combined cycle would not occur (or would occur at a much later date), and the opportunity to increase the generating efficiency of Units 17 and 19 would be lost or substantially delayed.

Similarly, with respect to Keahole ST-7, installation of that unit will complete the conversion of existing simple cycle combustion turbines Keahole CT-4 and CT-5 to a 2-on-1 combined cycle unit. The same concerns about competitively bidding the Maalaea Unit 18 would apply to Keahole ST-7. In addition, the completion of ST-7 is needed to place baseloaded generating capacity on the west side of the island for voltage support.

With respect to HECO's simple cycle peaking unit at Campbell Industrial Park and MECO's Waena Unit 1, which will also be a simple cycle peaking unit, competitive bidding was not considered because of the concerns identified above and in the responses to IRs.

Timeline for New Generation

The expected timeline (1) to complete an IRP cycle, (2) to bid, select, contract for and obtain approval for a new generating unit (whether an IPP or utility-owned unit), and (3) to then permit and install the new unit must be realistic, and cannot be based on wishful thinking to justify a competitive bidding process. The reality is that it takes substantially longer in Hawaii to complete many of these steps than on the Mainland, and that the time required for some of these steps has lengthened in recent years.

As HECO stated in its SOP, implementing competitive bidding must not negatively impact electric system reliability. Accordingly, a reasonable estimated timeline must be developed to ensure that the competitive bidding process is not applied to resources whose need date is earlier than could be achieved under a competitive bidding structure. See HECO SOP at 2-4. HECO estimates that it will take from nine to eleven years to install new firm generating capacity under competitive biding, including the time required for permitting, obtaining and installing the selected generating unit. See Response to PUC-IR-43.

A brief review of the major elements developing new generation through the competitive bidding framework clarifies the length of the process. The process includes completing this proceeding, developing the competitive bidding process, implementing the process, developing the RFP, obtaining bids and choosing a final project, negotiating the contract, obtaining required permits and approvals, and obtaining and installing the new resource. For various reasons identified below, some of these elements can take significantly longer than anticipated, especially in the Hawaii context.

HECO and its consultant estimate that, under the current schedule, it will take from 4 to 6 months to complete this docket. HECO is proposing that the competitive bidding process, including guidelines, be developed before the RFP is developed. Once the guidelines are developed, HECO anticipates that it will take from 12 to 24 months to approve the new competitive bidding process. See HECO SOP at 2; Response to PUC-IR-43.

Factors affecting the development and implementation of an RFP process include (1) whether or not competitive bidding rules or procedures were already in place before RFP issuance; (2) whether or not the host utility has had recent experience with developing and implementing an RFP process; and the (3) type of resources solicited. See Response to CA-HECO-IR 12. Based on examples of other utilities involved in competitive bidding, the time to develop and issue the RFP, evaluate bids and award the project, and negotiate and execute a contract can range from 14 to 31 months. See attachment to response to CA-HECO-IR-12. It is important to emphasize that this timeframe is predicated on the competitive bidding rules being developed before issuing the RFP.

By far the longest part of the process in Hawaii is obtaining the appropriate permits and approvals for new generation. Hawaii has a very limited number of sites that are available to locate new generation, and changing land use designations in Hawaii in order to acquire new generation sites is difficult and time-consuming with an uncertain outcome. Additionally, extended time must be allotted for permitting and environmental review. See HECO SOP at 4.

Any combustion based generation will require a Covered Source/Prevention of Significant Deterioration (CS/PSD) permit, which is administered by the State of Hawaii Department of Health (DOH) and the United States Environmental Protection Agency (EPA). The time necessary to apply for and obtain a CS/PSD permit varies widely depending on a number of factors including the size of the unit, its location, and the depth and extent of public participation or opposition. The permit review time period for recent HECO Companies units has varied from as much as 8.8 years (HELCO's Keahole CT-4/CT-5) to as little as 1.5 years (Maalaea X1-X2). See HECO Response to CA-HECO-IR-2. In general, larger units have a longer permit review period than do smaller units.

Besides CS/PSD permitting, all new or expanded fossil-fired electrical generation units with output exceeding 5 MW must now undergo environmental review pursuant to Hawaii

Revise Statutes (HRS) Chapter 343, Hawaii's Environmental Impact Statement (EIS) Law. The time necessary for the HECO Companies to complete the environmental review process under the EIS Law has ranged from 8 to 21 months for large projects (both generation and transmission). See Response to CA-HECO-IR2. It is important to note that the CA/PSD permit will not issue until the EIS process has been satisfactorily completed.

It is also important to understand that the above timeline discussion of timeline assumes that the site for new generation is appropriately zoned or has the appropriate land use designation. Rezoning or obtaining a change to the land use designation will only add time to the process.

Mainland Timeline

The time required on the Mainland to conduct and obtain approval of an RFP process, and to permit and install new generation, is considerably less than it is in Hawaii. Examples from Florida and Utah were provided in the response to PUC-IR-15, on pages 16-19.

In Florida, the competitive bidding rules were already in place, and Florida Power & Light Company ("FPL") simply filed a request for determination of need with a need study. It took six and one-half months from issuance of the RFP to submit the PSC petition, and three and one-half months for the PSC to issue its decision. The approved combined-cycle unit was expected to be available three years thereafter.

In Utah, interim competitive bidding procedures were adopted by stipulation within three months of the opening of a competitive bidding docket. It took five months from the issuance of an RFP for PacifiCorp (dba Utah Power & Light) to submit a CPCN application for a phased combined-cycle unit to be used for peaking purposes, and twelve months from RFP issuance to submit a CPCN application for a base-loaded combined-cycle unit. The PSC approved the respective applications after four months and five and one-half months. The first phase (a CT) of the first combined-cycle unit was expected to be available after fifteen months, with the completion of the unit in another year. The second combined-cycle unit was expected to take two and one-half years to install.

The timeframe to conduct an RFP process and to develop competitive bidding rules or guidelines has also taken a significantly longer amount of time, as is addressed in the response to CA-HECO-IR-12. In the case of Portland General in Oregon, which has been cited as a possible model, it took 28 months to adopt competitive bidding guidelines, and 27 months to develop an RFP, obtain bids and negotiate and execute contracts.

Other Limitations

HECO supports the option that competitive bidding should be encouraged, but not be required, for defined capacity needs of 25 MW or less.

Resource requirements that cannot conform to the time required to implement a solicitation process should be exempt.

In addition, it simply is not possible to precisely forecast what the future will look like ten years from now. Loads may grow faster than expected, the utilities may be unsuccessful in achieving the implementation rates that they have forecast for demand-side options, or other factors may accelerate the need for new generation. Just as IRP has to allow for the implementation of contingency options when planning assumptions and forecasts change, any competitive bidding process would have to allow for similar exceptions.

Also, any expansion or repowering of existing company units should be exempt. As an example, the recently developed Market-Based Mechanism to Evaluate Proposals to Construct or Acquire Generating Capacity to Meet Native Load in Louisiana identified several exceptions to the competitive bidding process, including resources less than 35 MW, modifications to an existing unit which expands the unit by 50 MW or less, and projects with a low installed cost. (See HECO response to PUC-IR-43.)

<u>As-Available Energy Generation</u>

As-available renewable energy generation has different characteristics than firm capacity, and the timing of when such resources are added to the utility's system is not nearly as important to the reliability of the system. It may be appropriate to establish a separate competitive procurement process to acquire as-available renewable energy generation, particularly given state energy policy that favors the development of renewable energy generation. (See HECO SOP, page 3.)

<u>Distributed Generation and Combined Heat and Power</u>

The competitive procurement process for distributed generation ("DG") may be different than the competitive procurement process for generation that provides power directly to the utility or sells power to the utility. The competitive procurement procedure that the HECO Companies propose to use for combined heat and power ("CHP") systems that are installed at customer sites was detailed in the generic DG investigation, Docket No. 03-0371. (See HECO SOP, page 3.)

A competitive procurement process can utilize a variety of approaches to meet its objectives, including issuing requests for proposals ("RFPs"), pre-qualifying bidders, or using strategic vendor alliances. As stated in HECO T-1 pages 32-33, an in HECO RT-1, pages 25-26, in Docket No. 03-0371, HECO's objectives of its competitive procurement process for combined heat and power (CHP) system equipment are, among others, (1) to ensure provision of quality CHP products and services, (2) to standardize equipment and designs, (3) to achieve efficiency in the equipment selection process, and (4) to obtain cost savings for the utility and its ratepayers, especially over the life cycle of the CHP installation. HECO may use a variety of processes to accomplish the needs of a particular project. (See response to PUC-IR-50.)

As for the process itself, HECO is considering use of elements from various approaches to procurement, including, pre-qualifying bidders, used of strategic alliances, and equipment bidding. The appropriateness of approach will depend somewhat on the project itself. For example, very large CHP systems may warrant use of equipment bidding due to the cost of equipment. Medium size projects might be bid or assigned to a more limited group of pre-qualified vendors offering either packaged or engineered systems. Small CHP systems might be procured via a strategic alliance with a qualified vendor of packaged systems. (See Docket No. 03-0371, HECO T-1, pages 32-33, and HECO RT-1, pages 25-26, as well as the response to PUC-IR-50 in this docket.)

The CA

The CA "recommends that a competitive bidding system be developed as the primary mechanism to be used by Hawaii's electric utilities for acquiring or building new generation in Hawaii . . . ." CA SOP at 3. When summarizing the actions that the PUC should undertake, however, the CA states that: "the Commission should establish competitive bidding as the mechanism by which new capacity and energy resources will be procured . . . ." CA SOP at 3, 44. The CA then explains that "[c]ompetitive bidding should be the default approach to securing new resources. The Consumer Advocate recommends that the Commission establish a rebut able presumption that competitive bidding will be implemented to address the incremental resource needs of all jurisdictional utilities." In the CA's view, "whenever energy resources are needed by regulated utilities competitive bidding, or some comparable form of competitive tests, should be the basic expectation." CA SOP at 45.

The CA, however, recognized that there would need to be exceptions to the requirement that resources be procured through competitive bidding, and that the urgency in which the resources needed would effect the decision to conduct the competitive bid process.

> Competitive bidding through RFPs can take time to implement and, while one cannot generalize very precisely, the time is months rather than weeks. This means that, for example, the near-term needs for short-term power supplies should be satisfied in other ways; similarly, where power supplies are needed to respond to an unanticipated emergency, competitive bidding will be too cumbersome.

CA SOP at 35.

The CA then indicated that, "[i]n circumstances in which a utility believes that there are reasons not to procure resources (or any particular resource) from a third party it should present supportive evidence during the IRP proceedings." CA SOP at 36. See response to HECO/CA-IR-33.b. Apparently, the CA would require the Commission to decide whether or not a competitive procurement process should be followed. See response to PUC-IR-6.

The CA also indicated that, where "the utility can demonstrate that reliability would be jeopardized by the utilization of a third-party resource, the Consumer Advocate would support not using a competitive solicitation." Response to HECO/CA-IR-31.a. The CA elaborated on factors that might be relevant to such a demonstration in its response to PUC-IR-6, and would include situations: (1) in which the winning bidder would place the utility in a position in which it was overly-reliant on third party; (2) where an existing third-party supplier or bidder with a low bid is in financial distress; and (3) where the specific need is such that the introduction of a third party would overly-complicate the situation for the utility.

3. Utility Role

HECO

The roles of the host utility in the competitive bidding process should include: (1) designing the RFP documents, evaluation criteria, and power purchase agreement; (2) managing the RFP process, including communications with bidders; (3) evaluating the bids received; (4) selecting the bids based on the established criteria; (5) negotiating contracts with selected bidders; and (6) competing in the solicitation process with a self-build option, if feasible.

All of these roles for the host utility are common in most RFP processes and are recognized by regulators and third-party bidders as a reasonable role for the host utility. Recent competitive bidding dockets have recognized the role of the utility and have supported an active role for the host utility. In fact, in several recent RFP processes, utility self-build or turnkey options have been the successful bidders among a large number of options, including recent Portland General Electric, PacifiCorp and Florida Power & Light RFP processes. See response to HREA-IR-10.

The goal of any competitive bidding process is to encourage and evaluate a range of generation options with the objective of obtaining the best possible option for the customers of the utility. This goal can only be assured if all resource options are allowed to compete. Regulatory commissions have recognized that a utility project may be the lowest cost option and failure to allow that option to compete may result in higher cost power options, contrary to their goals and objectives.

The CA

The CA identifies the proposed role for the host utility in the competitive bidding process beginning on page 48 of its Preliminary Statement of Position. The CA contends that the utility's roles in the process should include the following:

- The utility design its solicitation process, establishes criteria consistent with its overall IRP objectives, and specifies the timelines for the process;
- The utility develops the bid package that would be issued, which might include an initial notice, the RFP itself, sample contract for comment, and additional supporting material;
- The utility may or may not submit its solicitation design and bid package to the Commission for review and approval;
- The utility implements its RFP;

- The Commission resolves any disputes that arise between the utility and bidders or among bidders;
- The utility applies its bid evaluation criteria and selects the winning bidders;
- The utility submits the contracts for approval to the Commission;
- If the utility itself is to both bid and evaluate the bids, the CA strongly recommends an outside observer, whenever feasible; and
- The utility should identify the resources that it would implement in the event that the RFP fails to yield a desirable alternative.

The use of an independent observer, and the resolution of disputes, are discussed below.

HREA

HREA's position regarding the role of the utility in the competitive bidding process is sketchy. On page 9 of its Preliminary Statement of Position, HREA states that the IOU should have the opportunity to compete directly or via a utility-affiliate for the provision of wholesale power to the grid and ratepayers' interests would be protected by the likely result of competitive bidding approach to achieve lowest costs. However, the Model 1 option proposed by HREA appears to require more of a benchmark cost requirement. Not only does HECO take exception to the apparent inconsistencies of HREA's position with regard to self-build or affiliate option, but HECO is also concerned with the approach advocated by HREA in Model 1. The requirement in HREA's Model 1 that benchmark cost information should be published will send the wrong signal to bidders and could serve as a price cap. Bidders will attempt to price up to the cap but may not focus on preparing the lowest cost bid.

Furthermore, HREA proposes the use of an Independent Contracting Agent ("ICA") who solicits and reviews bids and recommends contract award. As discussed below, such a role for the ICA is beyond a reasonable role for an independent observer typical in the industry. Only the utility should have the authority to make such an important resource decision, subject to review and approval of the Commission.

4. "Fairness" Issues

a. Independent Observer

HECO

If utility-built and owned, or utility-owned turnkey facilities are included in an RFP process, HECO plans to retain an independent observer to review the solicitation process (including communications with bidders), bid evaluation and selection, and contract negotiations, and report to the PUC at various steps of the process.

If an Independent Observer is required, the Independent Observer selected should meet certain criteria, including:

- Be familiar with island utility systems and be aware of the unique challenges and operational requirements of such systems.
- Have the necessary experience and familiarity with utility modeling capability, transmission system planning, operational characteristics, and other factors that affect project selection.
- Have the capability of working with the utility during the evaluation process.

(HECO SOP, Exhibit A at 42)

In order to be effective, Independent Observers should have a demonstrated track record of impartiality, be able to work effectively with the utility over the long term, be knowledgeable about the unique characteristics and needs of the small, non-interconnected island electric grids, and have a working knowledge of common IPP contract terms and conditions, and the PPA negotiation process.

The role of the Independent Observer has not involved developing the bid evaluation criteria or making a recommendation for the project award. It is the appropriate role of the utility to undertake the evaluation of bids and make recommendations about the selection and negotiation of winning bids and is not a function that should be "outsourced".

It should be understood that the use of an independent observer will add substantially to the cost of an RFP process. It was reported in a recent bidding process on the mainland that the cost of the Independent Observer exceeded $500,000. HECO's competitive bidding consultant is aware of another competitive bidding process where the cost of the Independent Observer was approximately $1 million. HECO SOP, Exhibit A at 10.

<u>The CA</u>

The CA suggests that the utility could implement its RFP under the oversight of an independent observer, particularly in situations where the utility or a subsidiary intend to submit proposals. CA SOP at 49, 55. The CA's position is that each utility should have overall responsibility to design, develop and implement competitive bidding processes to meet its needs. In some circumstances, it may be appropriate to engage a third-party in an Oversight role, in order to most effectively conduct an RFP process (consistent with best practices). Certain functions could be transferred to that third-party, but not the utility's overall responsibility. However, there may be circumstances in which an independent observer would not be needed. <u>See</u> HECO-CA-IR-20c.

The CA does not envision a specific role for the independent observers with respect to competitive bidding processes in Hawaii, and states the role would vary, depending on the circumstances of the electric utility and the solicitation. (HECO/CA-IR-60d)

The CA suggests that it would be appropriate for the utility and not the Commission to hire an independent consultant to assist in the RFP process, stating that the Commission should defer to the electric utility and not have an active role in the RFP development process. (PUC-IR-56a,b).

On page 58 of its Statement of Position, the CA refers to FERC guidelines for competitive solicitations when affiliate transactions are involved, which FERC recited in Opinion No. 473; Opinion and Order Affirming Initial Decision in Part, Denying Requests for Rehearing and Announcing New Guidelines for Evaluating Section 203 Affiliate Transactions (issued July 29, 2004). The FERC guidelines include a role for an Independent Third Party that is not appropriate for Hawaii, and is not consistent with industry practices regarding state level competitive bidding processes. The FERC guidelines (which do not make competitive solicitations mandatory where utilities are acquiring facilities from affiliates, but recommends such solicitations) contain an oversight principle that includes a third party to design the solicitation, administer the process, and evaluate the bids (from both a price and non-price perspective). While the guidelines are not clear if the independent third party has the responsibility for selection of the preferred resource, it is HECO's position that the host utility has the responsibility to make the selection decision, not an independent party with no accountability regarding the outcome of its decision. The role for the utility in this regard advocated by HECO is entirely consistent with the role of the host utility in other state-level competitive bidding processes.

HREA

HREA proposes two models for implementing competitive bidding, both of which HECO has taken exception to in responses to IRs. Under Model 1 (Competition based on the Utility Proposal), the utility identifies a site and the need for capacity, and prepares the specifications for a new power plant, which serves as a facility bidding "baseline". The utility provides the baseline to an Independent Contracting Agent ("ICA"), selected and monitored by the PUC, who solicits and reviews bids and makes a recommendation for the project award.

HECO has major issues with this Model. First, the traditional role of the utility to procure power for its customers as part of its obligation to serve is abrogated. Instead, the ICA, with the approval of the PUC, is responsible for ensuring that the obligation to serve is met. The utility is not allowed to bid or evaluate bids. This could remove the lowest cost and most reliable option from consideration. Furthermore, the burden should be placed on the ICA and the PUC in case the process fails. While the risk of project failure would be significant in other interconnected markets where project failure could lead to higher costs, in a market such as Hawaii, the risks are magnified due to reliability concerns. Such an approach has never been applied in the industry where someone other than the utility has been held accountable for its resource procurement decisions. (HECO also has major issues with the requirement of the utility to identify a site for bidders.)

HREA's Model 2 (Open Competition with IPPs Only) also has major flaws. While the host utility is not required to identify a site for a new facility, the ICA is still the responsible procurement agent for the utility. A utility affiliate can bid as an IPP, but self-builds would not be allowed. Again, this may serve to eliminate the lowest cost, most reliable projects from consideration and lead to higher costs to consumers.

While HREA automatically assumes that competitive bidding will lead to lower prices and increased innovation, the two approaches it proposes appear to be inconsistent with these objectives by restricting resource options in the competitive bidding process and requiring that a third-party make the ultimate resource decision without possessing the system knowledge and resources of the utility.

The CA has also stated that it does not support HREA's proposed models (see response to PUC-IR-29). The CA refers to HREA's approach as a constrained approach to competitive bidding.

b. Utility Bids

HECO

The utility should be allowed to submit a bid in its own RFP. The goal of any competitive bidding process is to encourage and evaluate a range of generation options with the objective of obtaining the best possible option for the customers of the utility. This goal can only be assured if all resource options are allowed to compete, including a utility's self-build option. Regulatory commissions have recognized that a utility project may be the lowest cost option and failure to allow that option to compete may result in higher cost power options, contrary to their goals and objectives.

Utilities have been selecting their own self-build options more frequently over the past few years for several reasons. First, the financial and credit problems faced by independent generators have led to higher debt costs and higher equity ratios for independent generators, virtually eliminating the competitive advantage once enjoyed by independent generators. Utility projects are now competitive from a financial perspective. Second, transmission constraints in a number of markets have led to higher transmission costs for resources located outside the utility service area or in costly transmission areas. Third, the deteriorating credit quality of many independent generators has raised concern over counter-party reliability. In turn, power purchase agreements require higher levels of security and tighter damage provisions to protect the utility's customers against the prospect of contract default. There is heightened concern that independent generators are less reliable that host utilities in developing and operating their projects.

The CA And HREA

The CA states on page 59 of its Preliminary SOP that it can support the proposition that a utility may submit a bid in its own solicitation as long as the following guidelines are implemented:

- In the absence of any demonstrable benefits from the RFP, the Commission may direct the utility to proceed with developing its avoided unit;
- The utility must prepare a backstop plan (i.e., a specific unit that the utility will develop and put into rate base);
- If the utility bids, stringent rules must be included to protect against self-dealing;
- The utility must be held to the same performance, creditworthiness, and other evaluation standards applied to all bidders;
- If the utility submits one or more bids, the Commission should determine whether an outside observer is required;
- If the utility is allowed to compete, it should be held to cost-based ratemaking; and
- If the utility is allowed to compete directly in its own RFP, the utility should be held to terms that are consistent with the contractual terms that other bidders are required to follow.

See also CA's responses to HECO-CA-IR-45, PUC-IR-19 and PUC-IR-66, and HECO's response to PUC-IR-19 and PUC-IR-34.

HREA's position is that a utility "should have the opportunity to compete directly or via a utility-affiliate for the provision of wholesale power to the grid". HREA SOP at 9.

The CA has not defined what it means by stringent rules to protect against self-dealing, however HECO would propose taking the steps typical of utilities in other competitive bidding processes to protect against self-dealing. Therefore, as discussed elsewhere, HECO agrees to take steps to avoid concerns over self-dealing consistent with industry practices. For example, HECO suggests submitting its bid to Commission one-day in advance of receipt of all other bids. This ensures that, unlike HREA's proposal that the utility establish "binding" prices for its project when the RFP is issued, the utility will also have the option to develop its project and submit its final prices at approximately the same time as all other bidders, putting the utility's proposal on an equal footing with other projects. HREA's proposal would apparently have the utility include its bid price and specs in its RFP, months before other bids are received.

Given the dual role of the utility in the process, there are a number of steps the utility can take to avoid self-dealing or concern over an unfair competitive advantage that may be perceived by other bidders. These steps are discussed under "Transparency", below.

c. Transparency

HECO

HECO supports a competitive bidding process that is fair and equitable to all bidders, clearly informs bidders of the requirements for bidding, provides guidance to bidders regarding the basis for "winning the bid," and includes reasonably transparent evaluation criteria that informs bidders of the criteria of importance to the utility. Accordingly, the solicitation process should include thorough, consistent and accurate information on which to evaluate bids, a consistent and equitable evaluation process, documentation of decisions, and guidelines for undertaking the solicitation process.

It is HECO's position that the objectives of fair and equitable treatment of bidders and implementation of a reasonably transparent process can be met by use of a closed bidding process, which is more typical of current bidding systems in the industry. As HECO explained in PUC-IR-39, under a closed bidding system, the utility usually provides a reasonable amount of information about the evaluation process and the methodologies to be used to evaluate bids, the criteria of importance to the utility, in some cases, the indices allowable to bidders for incorporation into their pricing formulae, and the basis for selecting a short-list and final award group. The RFP requests information from bidders that is used in the evaluation. Under a closed system, the bidder does not have access to the utility's bid evaluation models or the detailed non-price criteria used to evaluate individual bids. Bidders, therefore, have to focus on developing the details of their own project consistent with the information requested by the utility to ensure the bid is competitive and reasonably mature rather than attempt to maximize the points they would achieve in an open bidding system. In HECO's view, a closed system is more equitable and fair to bidders since gaming is not possible and such a process allows for a more detailed and comprehensive evaluation of all bids. The models used are more sophisticated and allow for a detailed assessment of the system impacts of all bids, thus capturing the true costs to customers.

HECO supports the position that a competitive bidding process should not be an open bidding process. The early competitive bidding processes were largely open, self-scoring processes. As HECO has noted (see pages 1- 3 of Exhibit B of HECO's SOP), self-scoring processes encouraged gaming since bidders would attempt to present information in their bids designed to maximize their point totals only. As a result, these processes led to significant litigation since bidders knew their own scores and could guess the scores of their competitors. If bidders felt the scoring was in error, they would complain to the Commission. Furthermore, the price evaluation methodologies were simplistic, usually a spreadsheet which compared the net present value of the bid price against the net present value of the utility's projected avoided cost. Utilities were not able to optimize their portfolio because such simple models did not allow for project dispatching or reflection of other operating parameters associated with each proposal. Also, many of the projects accepted through these early self-scoring processes failed. Self-scoring systems are seldom (if at all) now implemented.

Where the utility is bidding on its own RFP, there are a number of steps the utility can take to avoid self-dealing or concern over an unfair competitive advantage that may be perceived by other bidders. These include:

1. The utility could submit its self-build option to the Public Utility Commission one day in advance of receipt of other bids. The utility could also provide substantially the same information as other bidders. By sending its proposal to the Commission in advance, other bidders would be ensured that the utility could not adjust its bid price or project structure after reviewing other proposals.

2. The utility could establish a website devoted to disseminating information to all bidders at the same time, including the utility self-build option. All bidders would therefore have access to the same information at the same time ensuring bidders are treated fairly and equitably.

3. The utility could use an independent observer to review the solicitation process including communications with bidders, bid evaluation and selection, and contract negotiations.

4. Resources permitting, the utility could establish a separate project team to undertake the evaluation, with no team member having any involvement in the utility self-build option. This would serve to mitigate any potential bias towards the utility's own self-build option. Unfortunately, completely separate project teams may not be practical for the small Hawaii utilities due to resource and personnel limitations.

5. In several states, the utility must abide by an established Code of Conduct that dictates the obligations of the bid evaluation team. Members of the project team may be required to sign confidentiality agreements.

6. Utilities have developed Procedures Manuals to guide the process. The Procedures Manual describes the protocols for communicating with bidders, the self-build team, and others, describes the evaluation process in detail and the methodologies for undertaking the evaluation process, contains documentation forms including logs for any communications with bidders, and other information consistent with the requirements of the solicitation process.

7. The utility can develop all the evaluation criteria, bid evaluation and selection guidelines, quantitative evaluation models and other information necessary for evaluation of bids prior to receipt of bids to ensure there are no biases in the process.

8. The utility, through the independent observer, could "blind" the bids before transferring the bids to the bid evaluation team to ensure the evaluators have no knowledge of the bidders and serves to mitigate any bias that may result from knowing the bidder.
HECO could agree to most of these steps should competitive bidding be implemented in

Hawaii. HECO does not think it is necessary to "blind" bids to avoid self-dealing. See response to PUC-IR-23.

The CA

The CA offers the following recommendation to ensure that competitive bidding is Hawaii achieves optimal results:

> Transparency in the process is critical. While a "transparency" requirement almost certainly falls within the domain of "best practices," a separate emphasis is warranted here. Ensuring both fairness and a healthy response to an RFP issued by a utility will depend on ensuring that, in both fact and appearance, a fair and level playing field is developed and implemented in evaluating bids. Put succinctly, the best way to achieve this objective is to ensure that the bid evaluation processes are understood by bidders and other external parties and the role of the utility or its affiliates as a participant in the bidding process is clear to all and at arms length from the evaluation of bids. The Commission should ensure that a utility's RFP design and bid package materials are developed in a manner that will ensure an appropriate measure of transparency.

CA SOP at 56.

The CA did not take a position as to whether an "open" or "closed" bidding system should be used, but recognized that an "open" system would be problematic. Response to PUC-IR-39.a.

In response to the PUC's request for the CA to specify the components of "appropriate measure of transparency" that the PUC should ensure that a utility's RFP design and bid package materials are developed to maintain, the CA defined transparency as the "degree to which the processes by which bids are evaluated and a winner selected are visible or otherwise discernable to the bidders and stakeholders." CA's response to PUC-IR-55.a. The CA went on to state that "a highly transparent solicitation would be one in which bidders would be free to sit as observers in an open meeting in which bid evaluators evaluated proposals and selected a winner." Id.

HECO interprets the CA's statement with regard to transparency as an example of a transparent process, but not as a component of the CA's position on the implementation of competitive bidding. Should this be the CA's position, HECO has major problems with this approach. If bidders and any other interested parties were free to sit in the room with bid evaluators during final bid selection and negotiations as the CA indicates, the process would deteriorate into chaos. First, HECO is not aware of any jurisdictions which have allowed for a "real time" review of the bid evaluation process by bidders. Second, such an approach would limit the number of bidders since bidders prefer to maintain confidentiality of their bids and not have other actual and potential bidders review their proposal. Third, the timeframe for completing bid evaluation and selection can take a number of days, which could make it difficult to accommodate the schedules of all who want to witness bid evaluation and selection. And fourth, bidders would second-guess the evaluator at every step of the way in an attempt to maximize their score. It is a process that is not workable and is akin to the early self-scoring competitive bidding processes that resulted in significant litigation and many failed projects. Such an approach should be rejected, as it has no inherent value for any stakeholder in the process.

HECO's proposed solution is to design a reasonably transparent bidding process, whereby bidders are informed in the RFP of the process used to evaluate and select bids, the evaluation criteria of importance to the utility, and the contract provisions of importance. See HECO SOP, Exhibit A at 41. Bidders need to know in general "how can I win the bid", but should not be in a position to influence the evaluation and selection process. As one solution to this issue, in other competitive bidding processes, the utility may meet with Commission staff to provide updates on the process. Furthermore, utilities generally develop thorough documentation of the evaluation and selection process for each bid, which can be reviewed with Commission staff at the end of the process. Another solution is for the utility to retain an independent observer, as is discussed elsewhere.

The CA further takes the position that the balance between transparency and confidentiality can and should vary from one RFP to the next depending on each utility's circumstances and specific needs. Examples of strategies to balance transparency and confidentiality cited by the CA include: (1) the use of an independent monitor whose role is to oversee the utility in bid evaluation processes and publish a report to the Commission addressing bid selection (2) accommodation of Commission review proceedings to address specific allegations of problems (e.g. conducted pursuant to signed confidentiality agreements); and (3) the publication of proposals, perhaps with redactions of certain particularly sensitive information.

It is HECO's position that, among the strategies suggested by the CA, the publication of proposals with possible redactions may not be useful or practical, given the limited value of such information after necessary redactions and the continuing concern over maintaining confidentiality of bidder information.

While noting that it has not surveyed the full range of measures to balance transparency and confidentiality in different types of solicitations, the CA references its response to PUC-IR-23, and the Georgia commission's recent promulgation of rules to address self-dealing. However, in keeping with the FERC's position on the matter, the CA recommends against prescribing measures to balance transparency and confidentiality, as the "best practices" in this regard may evolve over time.

d. Utility Staff

HECO

The measures that HECO could consider implementing to avoid even the appearance of self-dealing or an unfair competitive advantage, as may be perceived by other bidders or stakeholders, when the utility is proposing a self-build option, include:

1. The utility could establish a separate project team to undertake the bid evaluation, with no team member having any involvement in the utility self-build option. This would serve to mitigate any potential bias towards the utility's own self-build option.

2. In several states, the utility must abide by an established Code of Conduct that dictates the obligations of the bid evaluation team. Members of the project team may be required to sign confidentiality agreements.

3. Develop a Procedures Manuals to guide the process. The Procedures Manual developed by utilities describes the protocols for communicating with bidders, the self-build team, and others, describes the evaluation process in detail and the methodologies for undertaking the evaluation process, contains documentation forms including logs for any communications with bidders, and other information consistent with the requirements of the solicitation process.

Response to PUC-IR-23.

While HECO could consider implementing these collective measures, they would not come without a significant investment in time, expense and resources. For example, in undertaking a competitive bidding process, utilities generally establish several internal project teams for the price analysis, non-price analysis and contract negotiations. This usually requires several analysts to undertake the pricing assessment as well as representatives from a number of departments within the Company to undertake the non-price analysis (e.g. financial analysis, environmental analysis, fuels, engineering, transmission system analysis, operations, siting/land, and legal).

If the utility is proposing a self-build option, available resources may be further limited, or even unavailable, if a separate project team is formed to undertake the bid evaluation, with no team member having any involvement in the utility self-build option. Small utilities, such as HECO, may be particularly constrained in their ability to dedicate the appropriate amount of resources to adequately staff the project teams required. In other words, there are not enough people with the specialized skills to divide into the specific functions needed to carry out bidding and evaluation responsibilities, while at the same time being excluded from carrying out their planning and evaluation responsibilities with respect to the utility's own projects. Such a resource problem has existed for larger utilities, such as Portland General Electric, which presented a challenge for dedicating the required level of staff to the process. HECO SOP at 9-10.

HECO recognizes, however, that despite the expense and time required, the development of a Code of Conduct and appropriate confidentiality agreements is likely needed prior to issuance of the RFP to guide the roles and responsibilities of company personnel, particularly where the utility is proposing a self-build option.

Likewise, HECO also recognizes that development of a Procedures Manual, which describes the documentation process, reporting requirements, organizational structure, communications requirements, etc., is almost certainly required. HECO SOP at 36.

The CA

The CA recognizes that "where an electric utility has a need that must be addressed in order to ensure system reliability, the utility must put forth a proposal to meet that need, in keeping with its obligation to serve." CA's response to PUC-IR-65.a.

The CA in its SOP stated its position that "[a]ll-in-all, the Consumer Advocate can support the proposition that a utility may submit a bid in its own solicitation," as long as various guidelines it recommends are implemented. CA SOP at 59. The CA believes the guidelines recommended to the Commission are: (1) sufficient to ensure that the process is reasonably competitive; and 2) intended to strike a balance between the steps to ensure that competitive bid processes are fair and the cost of ensuring such fairness. The CA cautioned, however, that "because the steps are limited by cost considerations, they do not guarantee fairness in bidding processes." CA's response to PUC-IR-66.

e. RFP Review

HECO

HECO's proposed process leading to the distribution of the RFP would be based on the following steps:

- HECO develops the RFP and files a draft with the Commission and interested parties.
- HECO will hold a technical conference to review the RFP.
- Interested parties submit comments on the RFP and HECO elects whether to incorporate the comments or not.
- HECO will send the final RFP along with the comments of the parties to the Commission.
- If the Commission does not comment within 30 days the utility has the right to issue the RFP.

In HECO's view the timeframe associated with the process from issuance of the draft RFP to issuance of the final RFP should take no more than 75-90 days.

The CA

The CA has identified the following roles for the Commission in the competitive bidding process:

1. The Commission should not have an active role in the RFP development process. The Commission should defer to the utility and not have an active role in RFP development.

Rather, the Commission should review RFP designs to ensure that time and resources are not wasted on RFPs that contain fundamental flaws (see CA response to PUC-IR-56).

2. The role of the PUC is to review the RFP. Commission approval will be automatic after some amount of time has passed (see CA response to PUC-IR-56).

3. Under its oversight role, the PUC should require utilities to adhere to best practices and should avoid being prescriptive about how competitive bidding processes are to be conducted (CA SOP at 55).

4. The Commission should be responsible for dispute resolution.

HECO's comments on the CA's "best practices" approach are stated elsewhere. HECO supports the role for the Commission envisioned by the CA with regard to review of the RFP. This informal review process will serve to speed up distribution of the RFP as opposed to initiating a formal procedure to seek approval of the RFP.

HREA

HREA advocates a more active role for the Commission. Among the roles envisioned by HREA for the Commission are the following:

1. PUC will need to act as a watchdog to monitor and enforce the competitive bidding process to ensure it is fair and that broad participation is encouraged.

2. The PUC selects and monitors the Independent Contracting Agent ("ICA").

3. PUC approves ICA recommendations .

4. PUC monitors contract negotiations.

5. PUC approves the contract.

To fulfill the requirements outlined by HREA would require at least two Commission staff involved on a full time basis throughout the competitive bidding process. The role envisioned for the Commission by HREA is contrary with industry practices. Furthermore, under this suggested approach, the Commission will effectively be responsible for making the resource selection decision in the place of the utility since the Commission approves the recommendations of the outside entity it selects. This puts the Commission squarely in a role it has never provided and removes its authority to objectively approve cost recovery and rates.

HREA believes that Standard Offer Contracts ("SOCs") should be developed and implemented with industry input to minimize the number of disputes. The Commission's role would be to review and approval the SOCs. (See HREA response to PUC-IR-56.)

As discussed below, "Model" PPAs can be attached to an RFP, but it is not practical to issue a SOC. Pre-approval of the RFP might limit disputes, but it could also add to the time required for an RFP.

f. Dispute Resolution

HECO

HECO's position on the Commission's role in dispute resolution is as follows:

- HECO recommends that the Commission serve as an arbiter of last resort only after the utility, independent observer, and bidders have attempted to resolve any dispute or pending issue.

- HECO's recommended approach is to avoid placing the Commission in a direct day-to-day role to resolve every dispute that may arise between the utility and bidders or among the bidders and instead conduct informational meetings with the Commission throughout the process to keep them apprised of issues that arise among the parties.

The CA

The CA's position on the Commission's role in dispute resolution is as follows:

- The Commission should be responsible for resolving any disputes that arise between the utility and the bidders, or among bidders. (See CA SOP at 49.)

- The Commission can act to minimize the likelihood of disputes by ensuring that each electric utility takes its obligation to design effective solicitation processes consistent with best practices in the industry seriously. (See CA response to PUC-IR-45.)

- The Commission must be particularly attentive in its role as overseer of RFP design and implementation processes in the initial rounds of competitive bidding in order to help minimize the number of disputes. (See CA response to PUC-IR-45.)

HECO does not believe that the role of the Commission to resolve disputes between the utility and bidders or among bidders, as suggested by the CA, is an efficient or effective role for the Commission. Direct PUC involvement as a referee in the operations of the competitive bidding process will encourage bidders and others to frequently contact the Commission to favor their own cause and may jeopardize the fairness and objectivity of the competitive bidding process. For example, if a Commission staffer provides information to one bidder but not to another the integrity of the process can be compromised. HECO understands that in other processes where the Commission had a direct active role, it proved to be an invitation for bidders to contact the Commission to vent their concerns and attempt to achieve a more favorable result. See HECO response to PUC-IR-33.

To minimize disputes, provisions that can be standardized would be included in the "model" PPAs attached to the RFP. See response to PUC-IR-73. For provisions that are resource specific, or where options may be proposed, bidders should be required to specify such provisions and options in their bids, so that the "value" of their proposals can be considered in the bid selection process. If the Commission supports the utility's efforts to hold bidders to their bids (if they attempt to change the deal in the PPA negotiation phase), disputes will be minimized. (See HECO response to PUC-IR-45.)

5. RFP Process

a. Competitive Bidding Process

HECO

The HECO Companies propose that the competitive bidding process, if implemented as a result of this proceeding, be a multistage process involving (1) development of the RFP, (2) issuance of the RFP and development of bids by bidders, (3) evaluation of the bids, (4) contract negotiations, if a third-party bid is selected, and (5) regulatory approval. These stages are described in detail in Exhibit I.

The CA

The following generally summarizes the CA's positions with regard to the bidding process:

1. Each utility should design the RFP to meet its specific needs. If a targeted RFP is warranted, it should be developed (see CA's response to PUC-IR-57).

2. The RFP is issued to the competitive market. The RFP documents generally include a draft contract.

3. The RFP identifies the factors that will be used in evaluating bids, generally including price, and depending on the resource being procured, various non-price attributes.

4. Interested third-party suppliers (of supply and/or demand-side resource) would submit formal bids to the utility.

5. The utility would evaluate those bids based on predetermined criteria.

6. A contract would be signed, sometimes but not always after negotiations to improve the terms of the deal proposed by the bidder.

7. Some measure of review by the state public utility commission is typical.

In addition, the CA raises some other points about the competitive bidding process in its comments:

- The CA does not take a position whether the competitive bidding process should be designed as an "open bidding" process of a "closed bidding" process.
- A pre-qualification process may be appropriate to some bidding processes, depending on the circumstances of the utility and its specific need (see response to PUC-IR-59).
- The electric utility is responsible for the administration of the RFP.
- With regard to transparency, the CA states that a highly transparent solicitation would be one in which bidders would be free to sit as observers in an open meeting in which bid evaluators evaluated proposals and selected a winner.

HECO is in general agreement with the CA on its approach to the implementation of an RFP process. HECO's comments on the question of transparency are discussed under "Transparency".

HREA

HREA proposes a two-step process for implementing competitive bidding on page 13 of its Statement of Position. In Step 1 (Resource Assessment, Site Access, and Permitting) the bidder might propose a specific time period (i.e. one to three years) to complete resource assessment activities, an agreement to gain access to the project site, and time to secure a permit. In Step 2 (Negotiation of the PPA and approval by the PUC) after completion of the first step, which is generally required for an IPP to secure financing, the bidder would negotiate the PPA with the utility, sign and forward to the PUC for approval.

Frankly, this approach is fraught with problems and is totally contrary with industry practices. Under this approach, all the risk of project failure falls squarely on the shoulders of the utility and its customers. Since the IPP does not have to sign the contract until it has completed all tasks necessary to achieve financing, there are no penalties imposed on the IPP for project failure and no recourse for the Company or PUC to recover the costs associated with project failure or delay. Also, the IPP enjoys all contracting leverage since failure of the utility to sign the contract could lead to resource shortfalls.

Again, HECO recommends this approach be rejected out-of-hand as having no industry precedent and no value for anyone other than the potential bidder.

b. PPA Terms/Options

HECO

One of the major complexities often overlooked in competitive bidding processes is the development of power purchase agreements ("PPA") which ultimately specify the terms and conditions of products and services being bid. PPAs developed prior to the bidding process can help to organize and structure the process by specifying the terms and conditions to which all bidders must conform. A major difficulty is developing a PPA that can accommodate varying types of technologies and performance criteria. While a number of PPA provisions could be finalized prior to the bidding process, a number of the provisions cannot be finalized as such provisions will be based on the characteristics of the winning bidder's proposal (e.g., technology, location). For example, firm PPAs must have many more specific performance and enforcement provisions than as-available energy PPAs.

A contract negotiation issue that may arise following the awarding of a bid, is to what extent should the price and non-price terms of a PPA be subject to subsequent negotiation with the utility. Generally, in most RFP processes, bidders are informed that the price will be fixed in the PPA based on the bid. There may be opportunities to negotiate non-price terms to enhance the value of the contract for both parties. Examples of such provisions that may be open for negotiation include fuel supply arrangements and project operating characteristics. An IPP may be willing to offer the utility more flexibility if the plant can accommodate such operating flexibility in exchange for the utility agreeing to other non-price considerations.

In addition, there is an issue concerning the types of terms and provisions that should be included in a PPA to ensure that the winning bidder's project is reliable and meets the utility's needs. The isolated nature of Hawaii's electrical system places a premium on reliability of power supply and increases the risk of project default and/or the failure of the independent generator to deliver the power. Project failure, termination of a project, or poor operating performance could be particularly detrimental in Hawaii because unlike the mainland, Hawaii's electric utilities cannot resort to purchases of energy from the market during periods of generation shortfall if the project does not deliver the power as required under the PPA.

Contract terms and provisions are important for ensuring reliability and meeting utility needs. As a result, HECO will propose contract provisions designed to ensure that these needs are met. These will include:

- Reasonable credit assurance and security requirements designed to reflect the nature of the island system and compensate utility customers if the project sponsor fails to perform.

- Contractual terms to allow for turnkey options.

- Contract buyout and project acquisition provisions.

- In-service date delay and acceleration provisions.

- Liquidated damage provisions that reflect risk to customers.

Contract provisions such as high security requirements, stringent liquidated damages provisions and significant penalties for missing key milestones are PPA options that could be used for discouraging a developer from walking away from partially or nearly completed projects simply because the cost of completing the project and operating the facility were not economically viable. However, in an isolated island market such as Hawaii, where the utility does not have access to a broad power market to acquire replacement energy resources, the cost to customers for failure of the IPP to provide reliable service may greatly exceed these potential penalties and such stringent penalties may discourage bidders from competing in the solicitation process.

Another possible option to potentially mitigate the reliability risk to customers is to allow HECO the option to buy the awarded bidders project if the bidder defaults on the PPA. However, some of the practical challenges with this option include that the entity financing the project normally has first lien rights on the asset in case of default, relegating the purchasing utility to a lesser second lien position on the project.

Further, flexibility options such as contract provisions that provide for the acceleration or deferral of in-service dates should be included in PPAs. These provisions would provide to the utility some of the type of flexibility the utility would have if it constructed the facility itself.

Parallel planning is another option to mitigate risk, particularly given the isolated nature of Hawaii's utility systems. Under this option, HECO could continue to proceed with a self-build option until it is highly certain that the awarded project will meet its commercial operation date. Parallel planning, in general, would involve planning, permitting, and engineering activities that are required to be done to preserve the ability to construct the back up power plant. Usually, these parallel planning activities involve those critical or long-lead tasks, such as permitting, that are done early in the development of power plant projects, since several major permits require public hearings and do not have mandatory time frames within which the permitting agency must act.

The parallel planning could go on until it is clear that the winning bidder will reach commercial operation, or follow an alternative plan depending on the circumstances at the time. For example, if an IPP project fails after several years of development, there may not be sufficient time to complete the utility self-build. In this case, the utility may have to install emergency diesels or smaller units to buy time while the self-build is completed.

One option is for the costs of these parallel planning activities to be recovered from the winning bidder(s) as a condition of the PPA. For example, as a condition of the AES Barbers Point and Kalaeloa PPAs, each party paid HECO $955,000 to reimburse HECO for its parallel planning and preparation costs for the Kahe 7 project that these projects replaced. Such increase in the overall cost of power development may offset any hoped for cost savings benefit that competitive bidding is perceived to provide.

<u>The CA</u>

The CA did not attempt to list the terms and conditions that would be included in the form of PPA attached to an RFP. "The Consumer Advocate is confident, based on the years of experience that HECO has interacting with independent power producers that provide power to its system as a consequence of a prior competitive solicitation, that HECO has a keen understanding of the types of contractual terms that can be important in specific circumstances." HECO/CA-IR-30. Apparently, the terms and conditions would depend on the "specific circumstances of each utility's need, and the type, size, location and potentially other characteristics of proposed facilities."

HREA

HREA recommended in its proposed Model 1 that a standard offer contract be provided prior to the solicitation of bids. HREA's proposed standard offer contract is impractical. As previously discussed, while a number of PPA provisions could be finalized prior to the bidding process, a number of the provisions cannot be finalized as such provisions will be based on the characteristics of the winning bidder's proposal.

c. Turnkey Options

HECO

Turnkey arrangements should be allowed to compete in the competitive bidding process. Eliminating the turnkey option from the competitive bidding process could eliminate the lowest cost and failure to allow that option to compete may result in higher cost power options.

Turnkey options may offer the best option to meet the needs of the utility and other participants, particularly in a system such as Hawaii. Turnkey options allow project developers and/or EPC contractors to compete to develop and construct a project, thereby entering competition at this level. As a result, project developers can compete in the areas in which they are best able to absorb the risk (i.e., project development and construction). These developers will compete to provide the lowest cost option to the host utility. The utility will then own and operate the project, a risk it is best able to manage. This option minimizes HECO's concern over project reliability and provides the flexibility to not only operate the plant for the life of the plant but to change fuels or expand/retrofit the project if market conditions change.

Further, in conjunction with the inclusion of credit quality and financial impacts in the evaluation of PPAs, the inclusion of turnkey projects provides the correct signals for the bidder to structure its project recognizing the value of the project structure. For example, if bidders are concerned that a straight PPA will not be competitive if financial impacts are accounted for during the evaluation, the bidder will also have the option to offer a turnkey arrangement as well.

Soliciting turnkey options or purchases of existing or partially completed generation assets through a competitive bidding process is becoming very common in the power industry. For example, PacifiCorp recently selected a turnkey option through its 2003 RFP and has a draft RFP out soliciting turnkey arrangements among other options. HECO is aware that other utilities are also likely to solicit for turnkey options in upcoming RFPs.

d. Evaluation/Selection Criteria

HECO

One of the most important aspects of the competitive bidding process is the selection of the evaluation criteria and the associated evaluation process.

For the bid evaluation, most utilities utilize a multi-stage process designed to eventually reduce the bids down to a selected few or what is commonly called the award group. The multi-stage evaluation process generally includes: (1) receipt of the proposals; (2) completeness check; (3) threshold or minimum requirements evaluation; (4) initial evaluation including price screen/non-price assessment; (5) selection of the short list; (6) detailed evaluation or portfolio development; (7) select award group for contract negotiation; and (8) management (and sometimes board) approval of the contract(s).

It is HECO's position that each utility system is unique in terms of factors such as its existing resource mix, customer profile, transmission and locational issues, regulatory requirements, operational considerations and customer preferences. Evaluation criteria and the respective weight or consideration given to each in the bid selection process may therefore vary in certain respects from one RFP to another depending on the RFP scope and unique needs of a utility system at that time.

This is particularly important for an island system, where attributes such as quick load pick-up for proposed units, spinning reserves, redundancy criteria, ramp rates and load following capability, dispatchability, and other operational flexibility attributes are important, and should be required of bidders. Thus, it is not feasible to merely apply the same criteria from one or another RFP in a different jurisdiction to the Hawaii situation. Determining the factors and criteria for evaluation based on the utility's unique circumstances and specific needs is crucial for developing an effective competitive bidding process.

In the competitive bidding process, price criteria are generally balanced with non-price criteria to evaluate and select bids for a short-list or even final selection. HECO has indicated that both price and non-price factors will be considered in the evaluation of bids.

In order to ensure that the generation they acquire is at the lowest reasonable cost, utilities must be able to take into account *all utility cost impacts* that the addition of the new generation will have on the utility. Thus, all relevant costs should be recognized for each bid, in addition to the direct cost of the bid option itself. This includes the costs of transmission and interconnection requirements and system impacts associated with each project bid, system operational impacts, and the impacts of purchased power on the utilities balance sheet.

For example, if the addition of the new generation will require the addition of new transmission resources, then that will impact the cost of adding the new generation to the utility's system, and may also impact the amount of time required to add the new generation to the utility's system.

Moreover, where the utility would have to restructure its balance sheet and increase the percentage of more costly equity financing in order to offset the impacts of purchasing power on its balance sheet, this rebalancing cost must also be taken into account in evaluating the total cost of a proposal for a new generating unit if IPP owned.

On the issue of imputed debt and resulting balance sheet restructuring, it is noted that in the mid to late 1980s, before the integration of the Kalaeloa, AES and H-Power facilities into the HECO system, HECO's understanding from the credit rating agencies was that there would be no impact on its credit rating as a result of entering into firm power purchase agreements. The credit rating agencies subsequently changed their view of firm capacity arrangements, and began to impute debt, which resulted in the need to rebalance the utility's capitalization. Initially, imputed debt was based on 15% of the net present value of the fixed obligations under the power purchase agreement. This was subsequently increased to 30%. The Companies have rebalanced their capitalizations, and the rebalanced capitalizations have been recognized in the rate making process, but the need to rebalance has not been recognized in the calculation of avoided costs. See responses to CA-IR-19, HREA-HECO-IR-8, HREA-HECO-IR-26, HREA-HECO-IR-27.

More recently, new accounting requirements have raised issues as to whether power purchase agreements will have to be treated as capital leases, or whether the income statements and balance sheets of independent power producers will have to be consolidated with those of the utility. See Exhibit C to HECO's SOP, and response to HREA-HECO-IR-31. The financial impacts of such accounting requirements on the utility and its customers relative to IPP bid proposals would need to be considered.

Non-price criteria are crucial to assess the quality of each bid relative to the important characteristics unique to and identified in the RFP. The non-price criteria used in the evaluation process can be quite inclusive. Non-price criteria are generally defined in the following categories:

(1) Project development feasibility (siting status, ability to finance, environmental permitting status, commercial operation date certainty, engineering design, fuel supply status, bidder experience, reliability of the technology, etc.);

(2) Project operational viability (operation and maintenance plan, financial strength, environmental compliance, environmental impact, etc.);

(3) Operating profile (dispatching/scheduling, coordination of maintenance, operating profile such as ramp rates, quick start capability, etc.);

(4) Flexibility (in-service date flexibility, expansion capability, contract term, contract buy-out options, fuel flexibility, stability of the price proposal, etc.).

Another non-price factor that should be considered is the percentage of purchase power that a utility has and the impact on its operational flexibility. For example, while HECO has been able to manage the integration of the Kalaeloa, AES and H-Power facilities into its system, there is substantial uncertainty as to how much more firm power could be purchased without significant negative impact on HECO's operational flexibility. In particular, IPPs on Oahu are projected to account for approximately 42% of the total net-to-system energy by 2006. And while utilities have the obligation to serve their customers, IPPs who supply energy and capacity to the utilities may be obligated to provide to the utility only those items and services, or to perform only those duties, that are covered by provisions in the power purchase agreement. Unfortunately, power purchase agreements cannot be drafted to provide for all future contingencies and changed circumstances, thus constraining the utility's operational flexibility. In contrast, a utility has much more flexibility to adjust if it owns and operates its own units.

Ultimately, the weights for each non-price criterion are usually established based on an iterative process involving members of the utility's bid evaluation team and taking into account the relative importance of each criterion given system needs and circumstances in the context of a particular RFP.

Another issue is the type and form of non-price threshold criteria to apply for the competitive bidding process. Stringent threshold criteria (i.e. bidder has to have site control, maintain a certain credit rating, demonstrate the technology used is mature, have identified all environmental permits, etc.) are generally applied when the market is not very mature and the risk of project failure is great. Lenient threshold criteria are generally applied in a mature market or a case where market access to other resources is easy in case of project failure. HECO expects that more stringent threshold criteria will be necessary for the island systems since the risk of project failure can be significant for utility customers.

Finally, there can also be a challenge to combine non-price points with a pricing relationship between proposals. For example, the conversion of price scores to points is an issue that emerges in some bidding processes. As a result, many solicitations use the combination of price and non-price scores to select a short-list and then determine their portfolio based on price alone. On the other hand, while selection of the winning bid or portfolio of resources is generally based on price considerations, some utilities will use least cost as an indicator of selection but will use non-price factors as a "tie breaker". It is HECO's position that evaluation criteria and the respective weight or consideration given to each in the bid selection process may vary in certain respects from one RFP to another depending on the RFP scope and unique needs of a utility system at that time.

The CA

It is the CA's position "that evaluation criteria should be developed according to best practices in the industry." Response to PUC-IR-57.d. Furthermore, the CA states that determining which factors and mechanisms should be used to assess the proposals in a given evaluation process will require an assessment of the utility's circumstances and specific needs, and consideration of the best practices. Response to PUC-IR-62.

The CA, in its SOP, identified the following criteria that it deemed to be important for bid evaluation:

- Contractual terms and conditions are important to ensure reliability;

- Risk allocation in contracts;

- Counter-party creditworthiness;
- System reliability; and
- Bidder qualifications;

HECO agrees with many of the criteria or evaluation elements identified by the CA for the evaluation of bids. In particular, HECO agrees that determining the factors and criteria for evaluation based on the utility's circumstances and specific needs is crucial for developing an effective competitive bidding process.

Moreover, HECO believes, as does the CA, that contract terms and provisions are important for ensuring reliability and meeting utility needs. For example, HECO would propose contract provisions that include, among other terms:

- Reasonable credit assurance and security requirements designed to reflect the nature of the island system and compensate utility customers if the project sponsor fails to perform;
- Contract buyout and project acquisition provisions;
- In-service date delay and acceleration provisions;
- Liquidated damage provisions that reflect risk to customers; and
- Contractual terms to allow for turnkey options.

<u>HREA</u>

According to HREA, at a minimum, the evaluation criteria to be used by the Independent Contracting Agent (as opposed to the utility as HECO proposes) in reviewing and selecting the winning bid should include the following:

- Background experience and expertise of the bidder;
- Proposed technical approach to meeting the requirements of the RFP;
- Proposed management approach for the proposed project;
- Proposed cost for the delivery of electricity to the utility; and
- Contribution to the state's RPS law.

The evaluation criteria proposed by HREA were very limited and focused on the experience and approach of the bidder. HREA did not include other key evaluation criteria, such as the viability and feasibility of the project, project operating characteristics, creditworthiness of the counter-party and contract provisions that are applicable to most competitive bidding processes. HECO's position is that these criteria, among others as outlined in its position above, should be included in the RFP.

HREA also includes cost for delivery of electricity as an evaluation criterion. HECO proposes to include all costs associated with the delivery of power to the load in its evaluation including the direct cost proposed by the bidder, transmission and interconnection costs to deliver the power to the load, environmental costs, system operating costs, and debt impacts associated with purchased power obligations.

6. Integration With Other Processes

a. IRP

HECO

HECO discussed three approaches for conducting the IRP and competitive bidding process in its Preliminary SOP. See PSOP, Exhibit A at 17-20. HECO's preferred approach is the first one in which the IRP Plan can continue to be developed using the current process followed by the HECO Companies. In this case, the role of the IRP Plan should be to identify the preliminary "preferred" resource plan, define capacity and energy requirements, the timing of need, any preferred technologies, and potentially any other preferred attributes. The IRP Plan can also be used to identify any preferences or criteria for resource selection and can be used to determine avoided costs.

In this approach, the role of the RFP would include the solicitation and evaluation of resource options to meet the capacity and energy needs identified in the preliminary preferred resource plan. The RFP can be used to solicit bids for either a block of resources as defined in the IRP Plan or for the next required resource identified in the IRP Plan. Bidders would be allowed to submit proposals for any variety of resource types and sizes. The utility also would have the right to submit proposals for resources that may differ from the preferred resource type included in the preliminary resource plan.[4] The bids received in response to the RFP would be evaluated relative to one another and/or to the avoided costs of the generic resource identified in the IRP Plan or to the utility self-build project. The IRP Plan would establish the parameters (e.g., capacity and energy requirements, timing of need, any preferred technologies, potentially

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4 There is likely to be a reasonable time lag between the completion/submission of the IRP, review and approval of the IRP, development and issuance of the RFP, and receipt of bids. During that process, market conditions or technological advancements could change. HECO would, therefore, prefer to incorporate any changes in market conditions in its proposal similar to other bidders to ensure it includes the most up-to-date information available to provide the lowest reasonable cost option for the customers. As an example, Portland General Electric initially proposed F class technology for its preferred unit as an option for its 2003 RFP. However, the company conducted additional research, received pricing quotes from equipment vendors and eventually selected G class technology. This technology was slightly higher cost from a capital cost perspective but was more efficient with a better heat rate. In light of rising natural gas prices, the company preferred a technology that was more fuel efficient. Response to PUC-IR-34.

any other preferred attributes) for the RFP. After the bids are evaluated and the preferred resource selected, the utility would then build the resource (if a self-build system is selected), or negotiate a turnkey contract or power purchase agreement ("PPA") with the winning bidder (if a turnkey or PPA option is selected). The utility would essentially complete its preferred resource plan after the bids are received -- the final bid(s) selected would be part of the final IRP Plan.

Under this preferred approach, the role of the advisory groups will still be applicable for the IRP process and is not expected to change from previous IRPs. However, while the advisory groups may have input into the development of the RFP if a collaborative process is followed, the advisory groups will have no input beyond that stage. Information provided by bidders in their proposals and in contract negotiations is confidential and competitively sensitive. Any suggestion to disclose any of this information could violate the objective of encouraging broad participation in the bidding process. HECO could envision providing status reports to the Commission staff during the competitive bidding process, based on agreed upon confidentiality guidelines.

Should competitive bidding be implemented in Hawaii, revisions to the Framework for Integrated Resource Planning may be appropriate to account for the integration of the RFP process with the IRP process. It would be premature to propose specific changes to the IRP Framework before competitive bidding guidelines, if any, are adopted.

There also is a potential for tension between the resource selection procedure in an RFP process, and the selection of a preferred plan in an IRP process. There are procedures that can be used to mitigate, but probably not eliminate, the potential tension. That is one important factor to consider in determining whether a competitive bidding process should be used for all resources, or perhaps for selected resources. See response to PUC-IR-32.

The CA

The CA made some comments and proposals on the IRP process in its SOP. Specifically, these generalized IRP process concerns result in the following three primary recommendations by the CA for change to the IRP process:

> First, the Commission must make clear that utilities are required to provide stakeholders with detailed information regarding their needs at the outset of the "public participation" phase of the IRP review. CA SOP at 51.
>
> The Consumer Advocate also recommends amendments to the IRP rules to improve the overall timing of resource planning review cycles. CA SOP at 52.
>
> Finally, the Consumer Advocate recommends that the IRP Rules be amended to make explicit [that] the process by which utilities gain preapproval of capital improvements in excess of $2,500,000 should be amended to place upon an applicant the legal burden to demonstrate that a proposed electric generation project is consistent with its most recently approved IRP annual update. CA SOP at 54.

The HECO Companies note that the comments and proposals in the CA SOP at pages 51-54 relate more to concerns by the CA over the IRP process in general, as it presently exists, as opposed to IRP process changes that are crucial to the effective integration of a competitive bidding process with the IRP. (HECO discussed the differences between the HECO's preferred approach and the CA's approach in the response to PUC-IR-33.) HECO will address the CA's general concerns regarding IRP in the on-going IRP proceedings.

HREA

HREA proposed a number of changes to the IRP process. See HREA SOP at 19. HREA's proposals also relate more to concerns over the IRP process in general, as it presently exists, as opposed to IRP process changes that are crucial to the effective integration of a competitive bidding process with the IRP.

The HECO Companies do not believe that the success or failure of a competitive bidding process hinges on any of these changes to the IRP process proposed by the CA and HREA. While a competitive bidding process (if implemented in Hawaii) and the IRP process should be integrated, the Companies position is that the IRP Plan can continue to be developed using the current process followed by the HECO Companies. In this case, the role of the IRP Plan should be to identify the preliminary "preferred" resource plan, define capacity and energy requirements, the timing of need, any preferred technologies, and potentially any other preferred attributes. The IRP Plan can also be used to identify any preferences or criteria for resource selection and can be used to determine avoided costs. In this model, the role of the RFP would include the solicitation and evaluation of resource options to meet the capacity and energy needs identified in the preliminary preferred resource plan. The RFP can be used to solicit bids for either a block of resources as defined in the IRP Plan or for the next required resource identified in the IRP Plan. The utility would essentially complete its preferred resource plan after the bids are received – final bid(s) selected would be part of the final IRP Plan.

b. PURPA Rules

In the event it is determined that a competitive bidding process should be implemented, one subject that must be addressed is how will the competitive bidding process work in conjunction with the obligations of the utility under the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"), the rules established by the Federal Energy Regulatory Commission ("FERC") under PURPA, and state rules (such as those in Title VI, Chapter 74 of the Hawaii Administrative Rules ["HAR"]) implemented pursuant to the FERC rules.

The competitive procurement process that was implemented in Hawaii pursuant to PURPA is discussed in Exhibit III.

HECO

HECO's position is that for firm capacity resources, the way the competitive bidding process would work in conjunction with PURPA would be that when a utility identifies a capacity need, the utility could issue an RFP for a new resource. All supply-side options will be eligible to bid, including QFs. If the QF wins the bid, it will negotiate a contract with the utility for capacity and energy at the bid price, which effectively is the avoided cost. If a QF does not respond to the RFP, then it would not be entitled to a capacity payment as the project would not defer or displace any capacity.

The effect of this would be that for firm capacity resources, the competitive bidding process would take precedence over the requirement that a utility purchase capacity and energy at or below avoided costs from a QF under PURPA. In other states, the competitive bidding processes replaced the process for contracting with QFs from a cost-based approach to market-based approach and one designed to result in a greater level of benefits to customers, and were deemed consistent with FERC guidelines implementing PURPA.

For as-available resources, if there is an RFP, and the QF wins the bid, the QF will negotiate a contract with the utility for the energy at the bid price. For as-available resources, if there is not an RFP, the utility may still have to negotiate with developers on a project by project basis.

In order to effectuate that competitive bidding would take precedence over the requirement that a utility offer to purchase capacity and energy at or below "avoided costs" (determined based on a utility's base resource plan) from a QF under PURPA, the rules established by FERC under PURPA, and state rules implemented pursuant to the FERC rules, changes may have to be made to the state rules implemented pursuant to the FERC rules. Until such changes are made to the state rules, the utility might be subject to claims that the utility was obligated to negotiate for the purchase of capacity and/or energy at or below "avoided costs" from a QF outside the scope of an RFP. Of course, if the utility's needs for firm capacity are not through the RFP process, then the utility's "avoided capacity costs" for capacity offered outside the scope of the RFP would be deemed to be zero.

The CA

The CA recommends that the PUC "adopt a method for determining avoided costs that is consistent with all-source competitive bidding . . . ." CA SOP at 3, 24-25, 44. "To bring benefits to Hawaii and its consumers, the Commission should follow other states in establishing (as a matter of policy) that competitive processes will determine what is "avoided, and thus the pricing for long-term contracts should be consistent with the actual results of competitive processes." CA SOP at 50. The CA takes the position that the PUC "can establish competitive alternatives as the basis for establishing avoided costs in Hawaii simply by stating clearly this policy." Response to HECO/CA-IR-54.a. The CA assumes that this "policy" can be put into effect "in IRP proceedings and associated resource procurement proceedings . . . . by (1) calculating avoided costs based on information on resource options available to electric utilities in competitive markets (such cost information might replace, for example, avoided costs capacity and energy costs calculated based on existing utility generation), and (2) identifying the winning bid as the avoided facility when RFPs are issued (thereby allowing each RFP to specify a utility's purchase obligations under the Commission's existing PURPA rules)."

As is indicated above, some changes to the PUC's "Standards for Small Power Production and Cogeneration" may be beneficial to support changes in how the rules are implemented in connection with competitive bidding. See, for example, H.A.R. §6-74-15.

EXHIBIT III

HECO AND INDEPENDENT POWER PRODUCERS BACKGROUND

Introduction

A competitive procurement process was implemented in Hawaii as a result of PURPA. Qualifying facilities are allowed to submit offers to sell firm capacity and energy to the utility at prices at or below avoided costs, pursuant to the rules established by the Federal Energy Regulatory Commission ("FERC") under PURPA, and state rules (such as those in Title VI, Chapter 74 of the Hawaii Administrative Rules) implemented pursuant to the FERC rules. In Hawaii, the utility's resource plan generally is that developed pursuant to its IRP process, taking into account any updates based on more recent planning assumptions and forecasts. For firm capacity resources, avoided costs are determined using the Differential Revenue Requirements ("DRR") method, in which the utility's revenue requirements for its base resource plan are compared to the utility's revenue requirements (on a discounted present value basis) for a resource plan in which the Independent Power Producer ("IPP") facility is allowed to defer or replace utility-owned new generation.[1]

HECO and IPP's

In 1987, HECO used a Request for Proposals ("RFP") process to solicit proposals for new generation from IPPs. HECO has gained a great deal of experience with operation of electrical grids with substantial portions of the power provided by Independent Power Producers ("IPPs") since 1987, when HECO solicited power purchase proposals. As stated in Exhibit A, page 12 of the HECO Companies' Statement of Position ("SOP"), HECO now relies on

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1 Avoided costs for as-available qualifying facilities have been based on the short-run avoided energy cost rates filed pursuant to HAR § 6-74-18, or on negotiated prices that have been determined to be at or below avoided costs using methodologies such as the DRR method.

non-utility generation to meet a significant portion of its power supply requirements. The presence of a Power Purchase Agreement ("PPA") between the utility and an IPP does not provide the utility with as much operating flexibility as the utility has with its own units. In addition, a utility has much more flexibility to adjust to changed circumstances if it owns and operates its own units, than if it purchases power under long-term PPAs, because PPAs cannot be drafted to provide for all future contingencies and changed circumstances. Furthermore, existing IPPs have caused operational or reliability problems. See response to HREA-HECO-IR-9, pages 2-6.

The percentage of firm capacity provided by IPP's on HECO's system has increased from 0% prior to the RFP to approximately 25% today, and is expected to increase to about 26% once Amendment Nos. 5 and 6 to the Kalaeloa amended PPA become effective. The percentage of HECO's baseloaded capacity provided by IPP's is even higher – about 35% assuming Kalaeloa provides 209 MW.

	2004 IPP Capacity as a Percent of Firm Capacity	2004 IPP Generation as a Percent of Total Net-to-System Generation	2006 IPP Capacity as a Percent of Firm Capacity	2006 IPP Generation as a Percent of Total Net-to-System Generation
Oahu	25%	39%	26%	42%
Maui	6%	7%	6%	16%

HECO has been able to manage the integration of the Kalaeloa, AES and H-Power facilities into its system, but there is substantial uncertainty as to how much more firm power could be purchased without substantial negative impact on HECO's operational flexibility. Moreover, it is expected that there will be opportunities in the future to purchase additional renewables on a firm capacity basis (for example, if an additional waste-to-energy capacity is added at Campbell Industrial Park), and if the percentage of purchased power is increased, it should be accompanied with the benefit of adding renewables.

The most successful IPP projects have been those where the utility was able to take advantage of a resource that could be developed by a third-party with expertise in developing that resource. Examples would include PGV's geothermal facility, H-Power's waste-to-energy facility, Kalaeloa's facility, which was only the second combined cycle facility to be fired on LSFO (and which made the continued participation of the manufacturer of the facility an essential element of the power purchase arrangement), and AES Hawaii, which utilizes a circulating fluidized bed technology pioneered by AES. This consideration does not necessarily apply to future projects.

Financial Impact of Purchase Power Contracts

In the early 1990's, HECO's credit rating was downgraded, in part as a result of the risks associated with the purchase power contracts it signed in the late 1980's. Also in the early 1990's, S&P developed its methodology for taking the risks of purchase power into consideration in evaluating a company's credit. As a result, HECO increased its equity ratio in order to improve its key financial ratios. Thus, the HECO Companies have been required to rebalance their capital structures as a result of their purchased power commitments, by adding higher cost equity capital to balance the "imputed debt" attributed to existing non-utility power purchase agreements.[2]

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2 As indicated in the SOP, the credit rating agencies have determined that certain obligations of the Company that are not currently reported as liabilities on the Company's balance sheet should be reflected as debt in the ratios used to evaluate the Company's risk profile. In order to capture the risks associated with these obligations, the credit rating agencies calculate "imputed debt." Basically, rating agencies treat the fixed payments associated with power purchase agreements as debt on the utility's balance sheet since the utility has incurred an obligation to make

Financial ratio evaluations included in HECO's current rate case test year 2005 incorporate imputed debt of $247 million at the beginning of 2005 and $239 million at the end of 2005 for a test year average of $243 million. The amount of rebalancing to try to maintain target financial ratios varies from period to period and over time. However, as of December 31, 2004, if HECO had no purchase power obligations, approximately $100 million less in equity would have resulted in the same equity ratio as the ratio it had with the imputed debt (45%). Since equity investors require a higher return than debt holders, the increased amount of equity increases the cost of electricity to ratepayers. See response to HREA-HECO-IR-26; see also response to CA-HECO-IR-19.

The financial impacts on the utility's balance sheet associated with increased purchased power costs generally are more of a financial risk to HECO than to most mainland utilities with a lower reliance on long-term purchased power arrangements. The power purchase contracts between HECO and independent generators are long-term in nature and are exclusive with HECO, leading to long-term risk to the buyer. In fact, HECO is one utility that has already been required by rating agencies to rebalance its balance sheet by adding more equity to offset inferred debt from long-term purchased power agreements.

Several states have approved the inclusion of direct or imputed debt associated with purchased power commitments in the evaluation of resource options. For example, Florida utilities have included an equity adjustment in their RFP process. Also, the Florida Public Service Commission has acknowledged that an equity adjustment is appropriate to address the

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a stream of fixed payments to the seller over the life of the contract. Imputing or including the cost of purchased power as debt has the potential of adversely affecting a utility's capital structure and its interest coverage ratios due to this increased risk. A corresponding increase in the equity of the utility may be required to rebalance the capital structure and this cost needs to be accounted for in evaluating power purchase agreements. Because the cost of equity exceeds the cost of debt, this rebalancing of the utility's capital structure to accommodate the additional financial leverage of purchased power contracts imposes additional costs.

capital structure impacts associated with purchase power arrangements and it is reasonable to consider the financial impacts of purchased power. The Florida Commission determined that purchased power contracts imply higher debt leverage, and that the costs of rebalancing the capital structure to accommodate this debt should be considered in determining payments for purchased power. Other states such as Wisconsin, Utah, California, and Oregon have recently raised the issue for consideration of resource options. The Wisconsin Public Service Commission concluded that the utility must be compensated for the adverse impact on its capitalization associated with capital lease obligations arising from purchased power transactions.

The California Public Utilities Commission stated in Decision 04-12-048 (Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning, December 16, 2004):

> Debt Equivalence is a real cost that needs to be considered when evaluating bids from a PPA vs. a utility-owned resource. As SDG&E states, "[I]t is essentially undisputed that the credit analysts treat the utilities' long-term non-debt obligations, such as PPAs, as if they are in fact debt when they assess a utility's debt capacity." Consequently, the IOUs should take into account the impact of Debt Equivalence when evaluating individual bids in an all-source and RPS RFO, regardless of whether it is a fossil, renewable, or an existing QF resource. (Page 144)

Further, as a result of changes in accounting standards, HECO's accounting treatment may change. The changes in accounting standards may result in more <u>actual</u> debt being shown on HECO's financial statements as a result of either: (1) capital lease treatment or (2) consolidation of an IPP which is more highly leveraged than HECO. See Exhibit C to SOP; see also response to HREA-HECO-IR-8 (as replaced to include page 5 on May 5, 2005).

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that I have this date served a copy of the foregoing Final Statement of Position, Witness List and Exhibits I-III, together with this Certificate of Service, by hand delivery and/or by mailing a copy by United States mail, postage prepaid, and properly addressed to each such party:

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DATED: Honolulu, Hawaii, August 11, 2005.

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